Simpson

VIA ELECTRONIC AND OVERNIGHT MAIL

August 7, 2014

Dr. Jeff Johnston
Air Quality Science and Engineering Manager
Washington Department of Ecology
300 Desmond Drive, S.E.
Lacey, Washington 98503

Re: PSD-06-02 (Issued May 22, 2007)
Tacoma, Washington Kraft Mill
Supplement to 2010 PSD Amendment Application

Dear Dr. Johnston:

Enclosed please find the following information that Mr. Don Dossett of U.S. EPA Region 10 has requested. Simpson understands the purpose of this additional information is twofold; first, to allow the Agency to issue a formal determination confirming that applicable criteria for correcting the short-term and annual NOx BACT limits for Power Boiler No. 7 (PB-7) at the Tacoma, Washington pulp and paperboard mill (the "Tacoma Mill") have been met and second, to permit approval of Simpson Tacoma Kraft Company, LLC's ("Simpson") application to amend permit PSD-06-02 (the "PSD Permit") accordingly. As we have previously discussed, information requested by Mr. Dossett and enclosed with this letter is being provided to augment and amend Simpson's original 2010 PSD Permit amendment application submitted to Ecology. The amendment includes the following:

1) A July 28, 2006 letter from Jansen to Simpson titled "NOx BACT Review – No. 7 Power Boiler Jansen Project No. 2006-0021," which acknowledges the uncertainty of the 2006 permit application estimate of the post-modification NOx emission rate (**Appendix A**).

2) Substantial information on the types, quantities, and moisture content of fuels, especially purchased biomass, combusted before and after the modification to PB-7, documenting the moisture content of as-combusted biomass over time (**Appendix B**).

3) Information on PB-7 boiler operating loads and as-combusted fuel moisture correlated with NOx emission rates before and after the modification (**Appendix C**).

4) Substantial information on the chloride content of fuels and the hydrochloric acid (HCl) concentrations in the exhaust gas from PB-7, documenting the high chloride levels which would be available to react with ammonia (**Appendix D**).

5) An updated NOx BACT analysis for PB-7 to evaluate the cost-effectiveness of a technically feasible control scenario – a combination of controls to reduce HCl and NOx (acid gas scrubbing and selective catalytic reduction / selective non-catalytic reduction [SCR/SNCR] along with any needed improvements in particulate matter (PM) control) (**Appendix E**).

In addition, we are enclosing various background documents to ensure that the administrative record for the PSD Permit amendment is complete. **Appendix F** to this letter contains this documentation.

Relevant to EPA's determination, it is Simpson's understanding that the following three issues have been addressed with this submittal: (1) that the steam turbine generator cogeneration project, including associated changes to PB-7, was constructed in conformity with the PSD Permit; (2) that the NOx BACT limits for PB-7 contained in the PSD Permit are inaccurate as a result of errors, faulty data, or incorrect assumptions contained in the permit application; and (3) that Simpson investigated all available options to reduce emissions and demonstrated that compliance with the NOx BACT limits (both short-term and annual) for PB-7 cannot be achieved cost effectively using demonstrated technology.

As you know, RockTenn CP, LLC ("RockTenn") purchased the Tacoma Mill from Simpson on May 16, 2014. The PSD Permit and various other air operating permits and orders for the Tacoma Mill have been transferred from Simpson to RockTenn by the Washington State Department of Ecology ("Ecology"). By agreement with RockTenn Simpson is submitting the information required to finalize the PSD Permit amendment, but has consulted with RockTenn's engineering and environmental personnel on the technical evaluation presented in the updated NOx BACT analysis for PB-7 (Appendix E).

Please do not hesitate to contact me if there are any questions or concerns about this submission. Also, please feel free to contact RockTenn directly about this matter by contacting Nina Butler, Senior Vice-President, RockTenn Environmental. You can reach Nina by telephone at (770.326.8130) or by email at nbutler2@rocktenn.com.

We appreciate Stu Clark's April 18, 2014 letter confirming Ecology's continuing belief that the proposed amendment to the PSD Permit is fully consistent with federal and state regulations and guidance, as well as the Department's commitment to a speedy resolution of this matter. We look forward to working with Ecology and RockTenn to bring this issue to a successful conclusion.

Sincerely,

Dave McEntee
Vice President Operations Services

Enclosures

cc: Donald Dossett, Air Permits Manager, EPA Region 10
David Bray, Special Assistant to the Director, EPA Region 10
Garin Schrieve, Industrial Section Manager, Ecology
Nina Butler, Senior VP - Environmental, RockTenn
John Conkle, V.P. and General Manager, RockTenn Tacoma Mill

APPENDIX A

Customized Engineered Solutions

JANSEN Combustion and Boiler Technologies, Inc.

12025 115th Avenue N.E., Suite 250
Kirkland, WA 98034-6943 U.S.A.
Phone: 425.825.0500
Fax: 425.825.1131
www.jansenboiler.com

July 28, 2006

Via E-mail

Mr. Ron Stuart
Environmental Department
Simpson Tacoma Kraft Company
PO Box 2133
Tacoma, Washington 98401

Re: NO_x BACT Review - No. 7 Power Boiler
Jansen Project No. 2006-0021

Dear Ron:

Simpson Tacoma Kraft Corporation (STK) has contracted the services of Jansen Combustion and Boiler Technologies, Inc. (JANSEN) to assist with reviewing NO_x control technologies as part of STK's permit application for future operation of the No. 7 Power Boiler at its Tacoma mill. This letter report provides findings for use in developing the permit application.

Introduction

The No. 7 Riley Power Boiler will be upgraded later this summer with a JANSEN overfire air (OFA) delivery system for improved bark burning capability and fuel economy. After this upgrade, the boiler maximum continuous rating (MCR) will remain 300,000 lb/hr steam generation. At a later date, STK intends to raise the boiler operating pressure and steam generation rate to benefit a new turbine generator (TG). The new MCR will be 342,000 lb/hr.

The mill is in the process of acquiring the required permits for operating the upgraded boiler at higher capacity and the new TG. In preparation, an analysis is required of Best Available Control Technologies (BACT) for control of nitrogen oxide gases (NO_x) leaving the power boiler stack. STK has contracted with Geomatrix of Lynnwood to carry out the permit applications and address BACT issues.

JANSEN's role in the BACT review has been to provide technical background and cost estimates for available NO_x control technologies (four are under consideration) and help determine which of these will be suitable for use on the STK No. 7 Power Boiler.

JANSEN Combustion and Boiler Technologies, Inc.

Baseline NO_x and CO Emissions

Hourly average stack emissions data have been reviewed to help estimate the baseline emission levels for the No. 7 Power Boiler after the unit has been upgraded with the OFA system and operated at higher firing rates. Figure 1 presents reported NO_x and carbon monoxide (CO) emissions data as a function of oxygen concentration from STK's continuous emissions monitoring system (CEMS) for the first six months of 2006. The data can be summarized by the following points:

- The average NO_x and CO emissions over the entire six month period were 0.18 lb/MMBtu and 0.34 lb/MMBtu, respectively, at an average stack oxygen (O_2) level of 10.7% (dry by volume).
- The data shown in Figure 1 incorporates all firing conditions, including wood, natural gas, and oil co-firing.
- The magnitude of the NO_x levels are relatively low for a waste wood and oil co-fired boiler. NO_x levels are more typically in the range of 0.25 to 0.30 lb/MMBtu.
- The NO_x trends to lower values when the O_2 concentration is reduced, as shown by the linear regression line.
- Reducing the amount of oil firing in the boiler by increasing waste wood firing is expected to further lower the NO_x emissions. However, it is unknown whether the overall increase in load will increase the NO_x emissions rate in lb/MMBtu.
- The existing data show that CO emissions will start to rise as the O_2 concentration is further reduced. The improved mixing and combustion conditions created by the new OFA system is expected to maintain comparable CO emissions at lower O_2 levels.

At upgrade steam generation conditions of 342,000 lb/hr at 875 psig and 825°F, and an anticipated reduction in stack O_2 to 6.4% (dry by volume), the projected NO_x emissions rate is 0.15 lb/MMBtu. This will generate 380 tons NO_x per year at the upgrade conditions (65.4% boiler efficiency; 595.4 million Btu/hr heat input; firing only grate fuels).

NO_x Control Technologies

The following technologies to reduce NO_x were reviewed:

1. Flue Gas Recirculation (FGR).
2. Selective Non-Catalytic Reduction (SNCR).
3. Regenerative Selective Catalytic Reduction (RSCR™).
4. METHANE de-NO_x® ("reburning").

All four technologies are currently being practiced to reduce NO_x emissions from biomass and/or fossil fuel fired power boilers in different industries.

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Combustion and Boiler
Technologies, Inc.

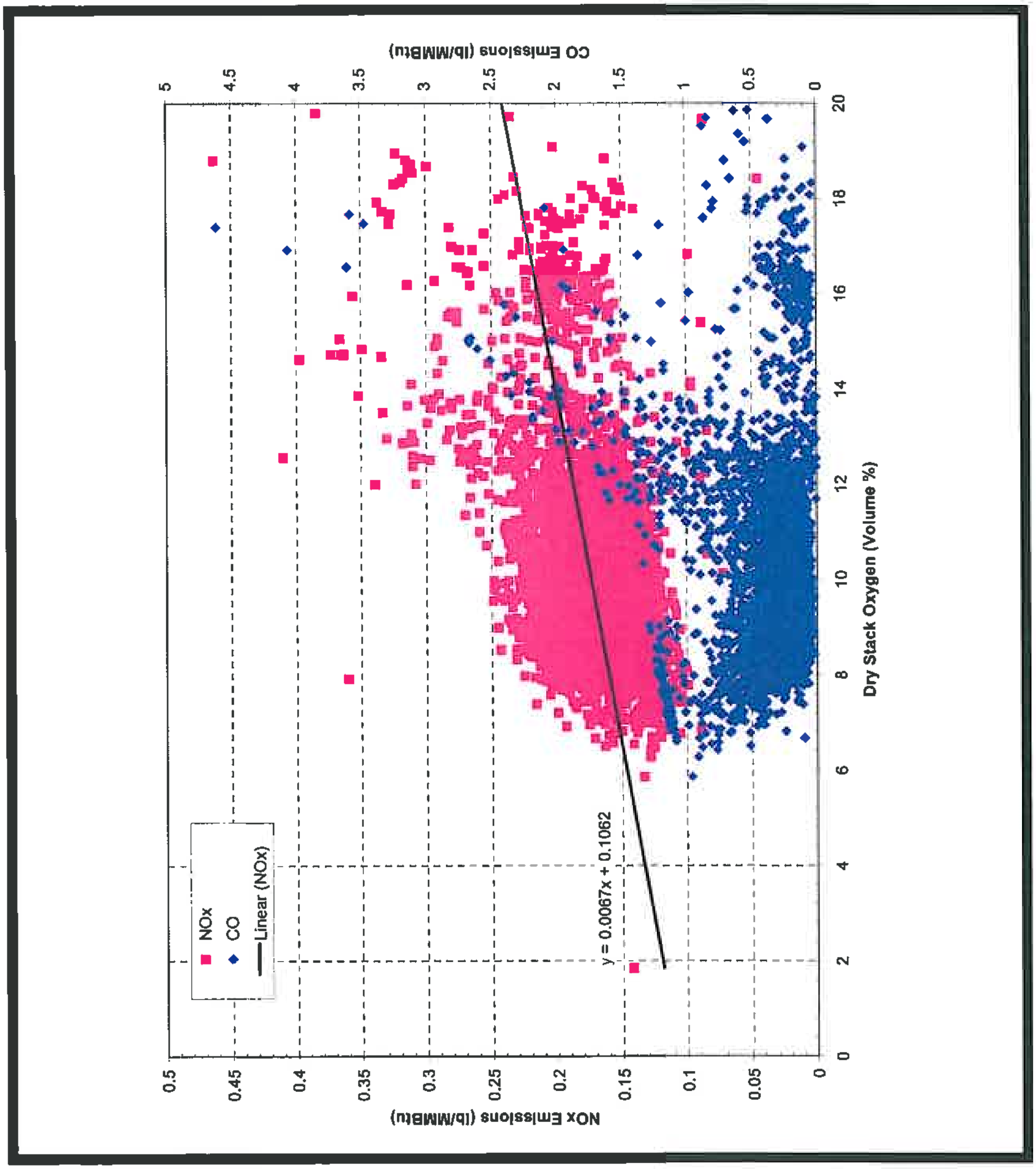

Figure 1. NO_x and CO Emissions versus Stack Oxygen (1/1/06 to 6/29/06).

Flue Gas Recirculation (FGR)

Flue Gas Recirculation (FGR) has proven to effectively reduce NO_x emissions on spreader stoker-fired boilers. The NO_x reductions provided by FGR are due primarily to the displacement of air in the combustion zone and reducing the overall excess air level. Operating adjustments to the FGR flow, UGA flow, and OFA delivery will influence the overall effectiveness of FGR.

For the STK No. 7 Power Boiler, it is estimated that FGR could be used to reduce the generating bank outlet oxygen level to about 1.9% (wet by volume at 14% excess air) at the upgrade steaming rate. Considering anticipated air in-leakage rates in the back passes, the corresponding stack oxygen level is projected to be 4.4% (dry by volume). This method would only provide NO_x reductions up to about 10% compared to the expected average emission rate after implementation of the OFA system. Considering that the oxygen levels in the furnace are being forced to low values, it is anticipated that CO emissions will increase when implementing FGR. Additional Computational Fluid Dynamics (CFD) modeling would help determine the amount of the increase before implementing FGR.

FGR requires installation of a hot duty fan to draw flue gas from downstream of the multiclone to feed the combustion air system. The recirculated flue gas can be supplied to individual air delivery locations, such as the UGA or various OFA levels, or to all air delivery locations. For our NO_x reduction estimates, it was assumed that FGR would be delivered to both the UGA and the OFA, but would not be delivered to the auxiliary burners.

A common difficulty with FGR systems is high maintenance costs associated with erosion. Extracting the flue gas from downstream of the precipitator or installing a small dedicated baghouse are options to consider if a cleaner flue gas stream is desired.

Selective Non-Catalytic Reduction (SNCR)

The Selective Non-Catalytic Reduction (SNCR) process involves injecting a chemical containing nitrogen in the furnace at temperatures of 1600-2100°F. The chemicals decompose, yielding NH_i species, which react selectively with NO in the presence of O_2, forming primarily N_2 and H_2O. SNCR is a proven technology that has been applied to over 30 grate-fired boilers burning biomass or a combination of biomass and fossil fuels. Chemicals patented for this process include ammonia (Thermal deNO_x), urea (NO_xOUT), and cyanuric acid (RapreNO_x). For this review, the NO_xOUT injection process was considered.

SNCR processes have several limitations which have previously restricted their widespread application, regardless of the chemical used. The most pronounced limitation is the relatively narrow temperature window over which these processes are effective. Temperatures in excess of the identified window can result in increased NO_x emissions levels, while temperatures below the window result in rapidly decreasing NO_x removal efficiencies as well as increased ammonia emissions. This temperature sensitivity makes the process difficult to implement on industrial boilers that swing with process steam demand due to their inherent temperature variations both spatially in the furnace and with load. These temperature variations are typically on the order of several hundred degrees Fahrenheit, resulting in significant impacts on SNCR process efficiency.

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Ammonia emissions in the stack ("ammonia slip") have been estimated to be between 5 ppm and 20 ppm following implementation of SNCR depending on the amount of reagent used and desired degree of NO_x reduction. This level is not expected to exceed regulated environmental permit limit requirements. However, the escaping ammonia will react with sulfur and chloride compounds in the flue gas to form fine particulate and produce a visible plume from the stack. This fine particulate has also been known to cause fouling of downstream heat transfer surfaces, particularly in tubular air heaters.

Regenerative Selective Catalytic Reduction (RSCR)

Selective Catalytic Reduction (SCR) is a proven technology in large utility applications for maximum reduction of NO_x. More than 75% reduction in NO_x emissions is typically achievable by applying this technology. SCR involves the installation of expensive catalyst material to react with injected ammonia and NO in the flue gas at relatively low temperatures. The catalyst is subject to poisoning and fouling in solid fuel-fired applications, resulting in degrading performance over a short time period and high replacement costs. The optimum injection temperature is between about 400°F and 780°F.

The Regenerative Selective Catalytic Reduction (RSCR) process is an emerging technology that reduces the rate of catalyst fouling in solid fuel-fired boilers by locating the equipment downstream of the precipitator. Some additional fossil fuel firing is then required at the catalyst inlet to raise the flue gas temperature to the optimum level for high NO_x reduction. Multiple catalyst modules are used in parallel to achieve regenerative heating of the flue gas and reduce the amount of fossil fuel firing required. An ID booster fan is also included in the system to overcome the pressure drop required by passing the flue gas through the catalyst matrix and the associated ducting and dampers. It is a very expensive system to install and operate, but offers very high NO_x reduction efficiencies.

Methane De-NOx®

Reburning is a NO_x control technology which uses staged air along with staged fuel to reduce NO_x emissions. A distinct fuel rich zone is created to promote NO_x reduction reactions. Key process parameters for reburning include heat release distribution, air distribution, and required residence times.

In reburning processes, grate conditions are established to achieve optimum combustion conditions without regard for NO_x emission levels. In the second combustion zone, a fraction of the heat input is injected above the grate creating a fuel rich region. Hydrocarbon radicals resulting from combustion of the reburn fuel react with the NO in the flue gas to form molecular nitrogen. The secondary fuel addition typically represents 8% to 20% percent of the total heat input, on a Btu basis. A flue gas recirculation system is used to help disperse the natural gas throughout the furnace cross-section. After sufficient residence time, OFA is added to burn out the remaining fuel rich combustion products from the reburn zone.

Methane De-NO_x® is a reburning process developed by the Gas Technology Institute (GTI) for stoker-fired boilers. In this process, natural gas is injected just above the fuel bed as a reburning fuel. The injected natural gas both reduces NO_x formed from the grate fuel combustion and limits its formation by decomposing a portion of the NO_x precursor species to form molecular nitrogen. This

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process was evaluated at pilot scale in 1991, and was demonstrated at full-scale in 1995 and 1996. In one case, NO_x reductions of 60% were achieved when injecting natural gas equivalent to 13% of the total heat input. However, unless a large amount of natural gas is already being co-fired in a boiler and can be shifted from the auxiliary burners to the reburning zone, the cost of adding natural gas firing becomes prohibitive. Consequently, very few industrial installations on biomass-fired boilers are in use.

Performance and Cost Estimate Summary

Table 1 (attached) summarizes the estimated NO_x emissions from implementing each NO_x reduction technology. Also presented is a summary of cost estimates associated with design, installation, operation, and maintenance of each technology, as well as discussion of pros and cons.

In general, there are a few particular constraints to implementation of NO_x control technology to this application:

1. The low NO_x emissions baseline makes further reduction more difficult due to the impact of lower concentrations on kinetic rates.

2. The presence of salt in the waste wood fuel supply, combined with ammonia that escapes to the stack ("slip"), will form a visible plume of ammonia salt.

Thank you for the opportunity to be of service to STK. If you have any questions, please contact me at 425.952.2832.

Regards,

John F. La Fond, P.E.
Manager, Process Technologies

JFL:pa

Attachment

cc: Greg Narum
Rich Crain
Eric Hansen
Arie Verloop
Marcel Berz

Table 1. Comparison of NO_x Reduction Technologies.

NO_x Control Technology	NO_x Emissions, lb/MMBtu (tons/yr)	Installed Costs (+operating and maintenance costs)	Pros	Cons
Baseline (342,000 lb/hr steam generation, with OFA, 35% excess air)	0.15 (380)	NA		
FGR	0.135 (342)	\$1.2 million +300 HP for FGR fan	• No ammonia salt plume. • Low operating cost.	• Small NO_x reduction. • Maintenance associated with erosion. • Potential increase in CO emissions.
SNCR I	0.10 (254)	\$1.5 million +22 gal/hr urea at \$1.50/gal	• Proven technology • Use on as-needed basis.	• 20 ppm NH_3 slip expected to result in visible plume. • Potential TAH fouling by ammonia salts.
SNCR II	0.12 (304)	\$1.5 million +16 gal/hr urea at \$1.50/gal	• Proven technology • Use on as-needed basis.	• 5 ppm NH_3 slip likely to result in visible plume.
RSCR	0.038 (95)	\$7.5 million +20 gal/hr #2 fuel oil at \$1.80/gal +14 gal/hr 19% ammonia at \$0.80/gal +1300 HP for booster ID fan +\$750,000 every 3 years for catalyst replacement	• High NO_x removal rate.	• 10 ppm NH_3 slip likely to result in visible plume. • High capital and operating costs. • Potential fouling of catalyst by sulfur and ash may reduce performance and increase replacement frequency. • Limited number of installations.
Methane De-NO_x	0.10 (254)	\$1.5 million +300 HP for FGR fan +1,200 SCFM natural gas at \$10/1000 ft^3	• No ammonia salt plume.	• High operating cost. • Limited number of installations.

APPENDIX B

Appendix B – Fuel Moisture Questions and Responses

EPA Question (From April 17, 2014 e-mail from Dave Bray of EPA to Lester Keel of STK)

Can STK provide the chloride content of the fuel that was burned during the HCl tests?

STK's Response – April 17, 2014

Please see the "2013 Fuel Chloride Test Results" section in Appendix E of this Supplement to 2010 PSD Amendment Application dated May 12, 2014.

EPA Question (From April 21, 2014 e-mail from Dave Bray of EPA to Lester Keel of STK)

Could STK provide the mean, maximum, and standard deviation of moisture content for purchased biomass for the categories of fuel that STK burned in 2011 and 2012 (C&D, land clearing, bark, urban wood, pallets, etc.) along with the total amount of purchased fuel in each category for the same time period?

STK's Response – April 22, 2014

SLR compiled moisture data from the fuel analyses provided on STK's behalf. These are analyses of delivered fuel.

Table 1. Moisture Content Parameters for Fuels Used 2011-2012

Fuel Type	Amount Used (BDT/yr)		Moisture Content (%)		
	2012	2011	Mean	Maximum	Standard Deviation
Purchased Biomass (Hog Fuel)	151,463	161,871	44.65	66.20	14.99

Table 2. Moisture Content For Urban vs. Non-Urban Wood, 2011-2012

Fuel Type	Moisture Content (%)		
	Mean	Maximum	Standard Deviation
Urban Wood	39.97	57.00	14.06
Non-Urban Wood	49.33	66.20	14.78

Table 3. Moisture Content of Purchased Fuel 2005-2012

Fuel Type	Year	Moisture Content (%)		
		Mean	Maximum	Standard Deviation
Purchased Biomass (Hog Fuel)	2005	37.58	62.20	17.29
	2006	31.56	48.70	7.87
	2007	33.85	40.20	9.68
	2008	--	--	--
	2009	--	--	--
	2010	45.84	63.10	10.31
	2011	40.69	63.60	18.08
	2012	47.47	66.20	12.01

STK has also provided monthly average data from grabs their operators take every few hours from the belt feed to the boiler. This is "as fired" data and it reflects fuel coming directly from the hog fuel pile. To assure quality averages implausible data are deleted. Fuel less than 20% moisture is extremely unlikely. Most of the deleted data were single digit and zero percentage readings that operators recorded erroneously.

Date	Fuel Moisture % (deleted less than 20%)
Jan-11 Average	57.5
Feb-11 Average	53.4
Mar-11 Average	55.2
Apr-11 Average	52.9
May-11 Average	45.6
Jun-11 Average	46.1
Jul-11 Average	42.6
Aug-11 Average	41.4
Sep-11 Average	42.2
Oct-11 Average	48.2
Nov-11 Average	48.8
Dec-11 Average	49.6
Jan-12 Average	54.1
Feb-12 Average	55.2
Mar-12 Average	55.2
Apr-12 Average	50.6
May-12 Average	50.5
Jun-12 Average	45.7
Jul-12 Average	42.6
Aug-12 Average	41.1
Sep-12 Average	39.1
Oct-12 Average	39.8
Nov-12 Average	50.0
Dec-12 Average	52.6

Date	Fuel Moisture % (deleted less than 20%)
Grand Average	48.4

When fuel moisture gets too high STK can have problems with carbon monoxide (CO) and boiler efficiency goes down. When these issues are profound STK has sought drier fuel. But, for the most part, STK's hog fuel supply is variable and as-fired moisture content percent ranges from the mid 30s to the upper 50s. The fuel is wetter in the winter and drier in the summer.

When fuel moisture is higher one would expect to see lower nitrogen oxide (NOx) (and higher CO). Conversely, when fuel is drier one would expect to see higher NOx. This is a bit simplistic, though. Note that when fuel moisture is high, NOx concentration might be lower, but boiler efficiency is markedly affected by fuel moisture and one would need to burn more fuel to make the same amount of steam. So, more fuel means more emissions, particularly when a lot of NOx from wood combustion comes from fuel nitrogen. It depends on the basis for the NOx emission expression.

EPA's Questions (From April 23, 2014 email from Dave Bray of EPA to Lester Keel of STK)

Are the means in Tables 1-3 weighted averages or just simple averages of the moisture content of each purchase regardless of quantity?

Is there a reason why STK didn't include moisture content data for 2008 and 2009?

To help paint a fuller picture of the info in Tables 1 and 2, could STK provide EPA with the quantity of "urban wood" and "non-urban wood" for 2011-2012?

Given that STK stores all of its purchased biomass outdoors, does STK have any feel about how much the moisture content of the "as-fired" fuel changes after STK receives it from its suppliers?

In the STK-NOx-HCL Briefing document provided back on April 10, STK had a graph of NOx 30-Operating-Day rolling averages for July 2012 to present. Does STK have similar NOx data going back to the pre-generator project timeframe? EPA is wondering if there was actual NOx emissions data that could be used to pinpoint when the boiler's emissions changed from the pre-modification rate of around 0.18 lb/MMBtu to the current levels.

STK's Response – April 24, 2014

The averages are simple averages, not weighted averages. STK calculated a weighted average for 2012 and obtained about 45% versus about a 47% arithmetic average.

The moisture data shown in tables 1, 2, and 3 were derived from lab analytical results from samples taken for chloride (and sometimes mercury) analysis. STK did not do any of these studies during 2008-2009, and hence there is no moisture data for those years.

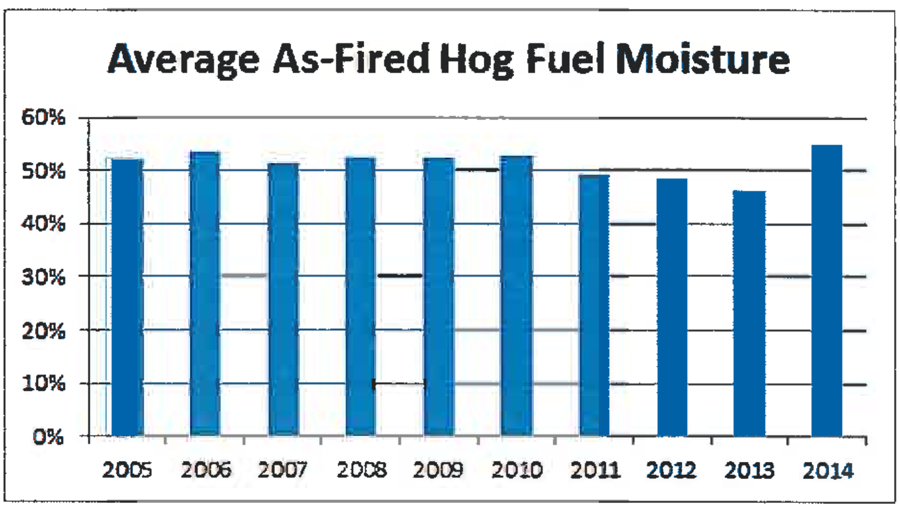
The quantity of urban versus non-urban wood consumed in 2011 and 2012 is shown in the table below:

Year	Total Urban (BDT)	Total Non-Urban (BDT)
2011	95,636.63	68,043.91
2012	111,010.84	48,598.35

STK does not have a good sense of how the as-fired fuel changes given that it is stored outdoors. The changes in moisture content could depend on whether it is raining or not, what the fuel is, how wet it is beforehand, how long it sits in the pile, and its position in the pile.

As additional background, STK also has data on belt-feed fuel moisture, which better reflects the moisture of the fuel which is actually burned. The (belt feed) fuel moisture is consistent from 2005 through 2010, drops a few percentage points during 2011 through 2013 before rising again so far this year. The yearly averages are:

Year	Average As-Fired Hog Fuel Moisture
2005	52%
2006	54%
2007	51%
2008	52%
2009	52%
2010	53%
2011	49%
2012	48%
2013	46%
2014	55%

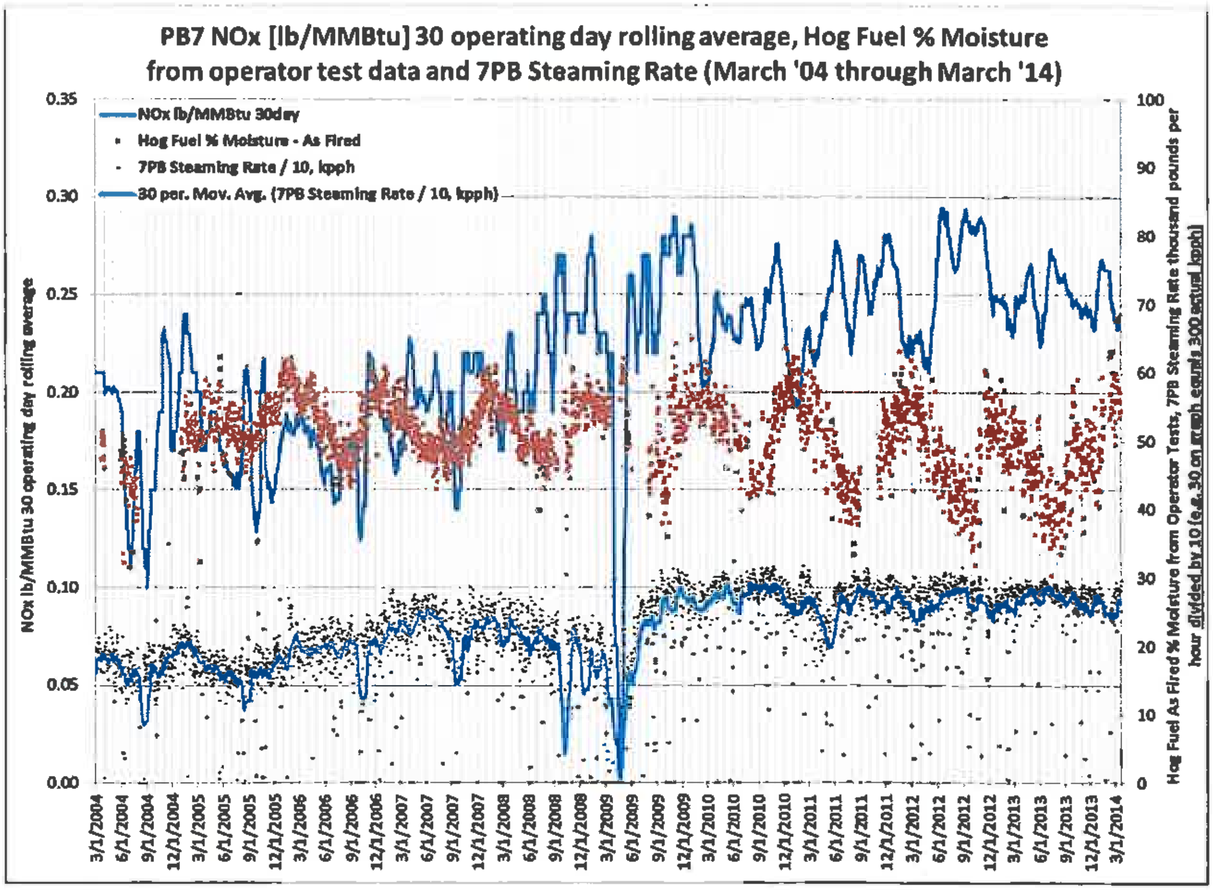


As mentioned previously, STK has pursued drier fuel at times when CO emissions and boiler efficiency become issues during the wet season. Other than these discrete times STK has not purposefully pursued a particular fuel moisture content.

APPENDIX C

Appendix C – Fuel Moisture Correlated with NOX Emission Rates

The graph below is busy, but it charts NOx lbs/mmBtu over time and it shows as-fired hog fuel moisture and two expressions of PB7 steaming rate (1/10 scale to make it fit). Note that the 0.18 lb/mmBtu figure quoted actually represents a range of between about 0.13 up to 0.24 lb/mmBtu, and was occurring during a period when the steam load was generally less than 200,000 pounds of steam per hour.



The higher NOx emissions resulted from the higher firing rate of the boiler. This effect can be seen even in late 2004 and early 2005. After cogen startup in 2009, with the boiler now operating near 300,000 pph steam, the NOx has stayed in the 0.2 to 0.28 lb/mmBtu range, with the variation also due to fuel moisture content. Additionally, increased reliance on hog fuel, instead of fossil fuel, increased NOx emissions (more fuel nitrogen). A higher firing rate with hog fuel was the intent of the cogen project and was addressed by the permitting process. As expected, seasonal upward swings result from lower fuel moisture, and NOx emissions are depressed when fuel moisture is high (and CO increases). Marginal additional improvements may be possible, but not to the extent they will bring NOx emissions below 0.2 lbs/mmBtu. (see Tim Sonnichsen's report below). STK is not exactly sure of the cause of the increased NOx as the boiler load was decreasing in 2008. The most plausible explanation is an upswing in natural gas usage for cofiring at that time. The natural gas burners emit high NOx and present a fairly low heat input, so lbs/mmBtu goes up. Fortunately, STK tries to avoid cofiring.

SONNICHSEN ENGINEERING, LLC

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April 9, 2014

Mr. Lester Keel, P.E.
Environmental Manager
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

Subject: **Power Boiler No. 7 (PB7) - Additional Operational Adjustments to Better Control Nitrogen Oxides (NO_X) and Carbon Monoxide (CO) Emissions**

Dear Lester:

The Simpson Tacoma Kraft Company's (STK) PB7 at their mill in Tacoma, Washington is currently subject to emission limits of 0.30 lb NO_X/mmBtu and 0.35 lb CO/mmBtu on a 30-day rolling average. Mill personnel have requested input by Sonnichsen Engineering (SE) on the feasibility of reducing the NO_X emission limit to 0.20 lb/mmBtu through changes to the boiler's combustion system while maintaining compliance with the CO limit.

SE has been assisting the mill in controlling NO_X and CO emissions since the summer of 2012. Efforts have included a series of field tests on the boiler in July 2012 that involved adjustments to the boiler's Jansen overfire air (OFA) system to improve air mixing above the grate and lower overall excess air levels. Several recommendations were made for operational and hardware changes. These tests and recommendations were documented in SE's July 25, 2012 report. Follow-up visits to the mill were made in late 2012 to assist in implementing the operational changes. The mill subsequently made several of the recommended hardware changes during the 2013 and 2014 shutdowns.

Analyses of the NO_X and CO emissions data by mill personnel have indicated improvements in both emissions following the 2012 efforts. NO_X emissions, which had peaked to very near 0.30 lb/mmBtu in June and early July 2012, have been consistently near 0.25 lb/mmBtu since the beginning of 2013. CO emissions, which had exceeded the 0.35 lb/mmBtu limit in June 2012, have also been near 0.25 lb/mmBtu over the same period of time. Clearly, the efforts made by the mill have succeeded in better controlling emissions.

SE does not believe it will be possible to extend these efforts and further reduce NO_X emissions below a 0.20 lb/mmBtu limit without adversely affecting CO for the following reasons:

1. **Previous Recommendations**. The July 2012 recommendations were primarily directed at improving combustion conditions to obtain better control of CO emissions. It was also expected that excess air levels could be reduced and thereby achieve a small (~10 percent) and consistent NO_X reduction. Based on the recent data available, both objectives have been achieved.

2. **Combustion Stoichiometry**. The principle factor that determines NO_X emissions from a wood-fired boiler is the combustion stoichiometry (availability of oxygen) in the region where the nitrogen contained in the organic structure of the fuel is released. For wood-fired boilers, this region is in the lower furnace on or just above the grate surface.

Conventionally designed wood-fired boilers typically operate with high levels of excess air with the bulk of the air added from below the grate. Efforts to reduce excess air, achieved by lowering the delivery of air from below the grate, are able to only marginally affect stoichiometry and NO_X emissions.

Additional NO_X reductions would require operating at a much lower stoichiometry without adversely impacting combustion conditions on the grate. A high capacity and specially designed OFA system would also be needed to effectively deliver air above the grate to control the associated increases in CO. The Jansen OFA system, as installed on PB7, does not meet these criteria. (Unfortunately, even the most advanced OFA designs often fail and do not simultaneously achieve high NO_X reductions and low CO. Excessive levels of incomplete combustion on the grate can also occur. Application of combustion hardware modifications directed at significant NO_X control on wood-fired boilers is, therefore, generally not applied.)

Available methods to further reduce stoichiometry conditions on PB7 by reactivating the original OFA system (as recommended in the July 2012 report by SE) or utilizing the out-of-service natural gas burners (as suggested by others) will not likely sufficiently effect stoichiometry and/or provide adequate air mixing to control CO.

3. **Other Factors Affecting NO_X Emissions.** Fuel nitrogen content, combustion temperatures, and fuel quality (moisture content and size) also directly or indirectly affect the quantity of NO_X produced in a wood-fired boiler. These factors, however, are not controllable, tend to increase CO, and/or have only a minor affect on emissions, and therefore are not generally part of an NO_X control strategy.

4. **Achieved NO_X Emission Reduction.** Current NO_X emission levels represent a ten percent reduction from the "as-found" levels in 2012. This was the level of improvement expected by manipulating the quantity and distribution of combustion air delivered to the furnace within the limitations of the Jansen OFA system. (Similar reductions have been demonstrated numerous times during comparable wood-fired boiler NO_X and CO emission control projects.)

5. **Additional NO_X Emissions Reduction.** Compliance with a limit of 0.20 lb/mmBtu would require an additional 30 percent decrease in NO_X emissions from the recently reduced emission levels. To my knowledge, a cumulative NO_X reduction of this magnitude has never been achieved without a complete changeover in the wood firing system (as for example, a retrofit to a fluidized-bed combustor) or the use of an ammonia-based post-combustion selective catalytic (SCR) or non-catalytic (SNCR) NO_X reduction system.

Please call or email if you have questions or require additional information.

Regards,

SONNICHSEN ENGINEERING, LLC

Tim W. Sonnichsen

Tim W. Sonnichsen, P.E.

Cc: Nathan Pearson, STK

APPENDIX D

Appendix D – Fuel Chloride Content

STK Fuel Trial Results (feasibility of achieving Boiler MACT HCl limit through fuel management)

HCl Stack Test Emissions

STK has tested a number of fuels in 2013 and 2014 in an attempt to find fuels which will result in emissions below the Boiler MACT limit of 0.022 lb/MMBtu HCl. STK has been unsuccessful in finding such a fuel source, however. The graph below shows emissions profiles of fuels tested by STK, in 1-hour averages (for 2014 tests) or 1-minute averages (for 2013 tests). All fuels tested by STK in 2013 failed to meet this emissions level, as seen in the graph below. In 2014 testing, only chip screening fines have resulted in emissions meeting the Boiler MACT standard.

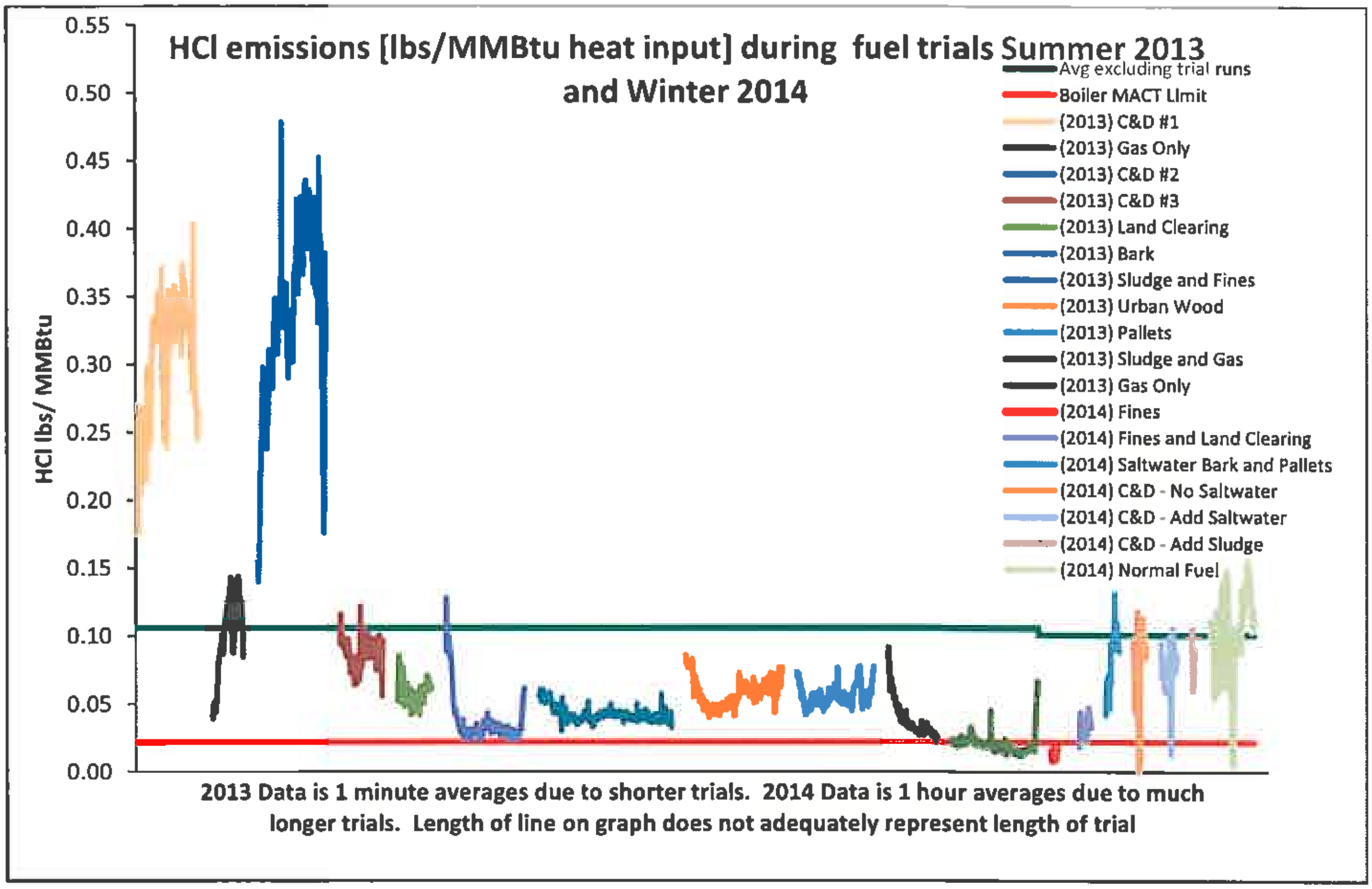

Figure 1 - HCl Stack Test Emissions. Over 1000 hours of continuous measurements via FTIR were conducted in 2013 and 2014.

Summary of the Chlorine Content of Fuel in PB7 (Excluding Fuel Oil and Natural Gas)

The following section summarizes data regarding the chlorine content of the fuel. The table below summarizes the maximum, average, and standard deviation of chloride fuel content for the different types of fuels used in PB7. The sample data comprises laboratory tests from 2005 to 2013. The graph below it illustrates the percentage of fuel consumed (in terms of the Btu) by PB7 in 2011 and 2012. The percentages do not add to 100 percent as about 5 percent of the Btus consumed in 2011 and 2012 were provided by natural gas, which is not shown in these graphs.

Average and Maximum Chloride Content by Fuel Type			
Fuel Type	Chloride Content (lb/MMBtu)		
	Average	Maximum	Standard Deviation
Purchased Biomass	0.14	4.66	0.51
Dewatered Biosolids – Primary	0.35	4.27	0.62
Dewatered Biosolids – Secondary	15.01	29.68	8.57
Old Corrugated Containers (OCC)	0.16	0.67	0.27
Fines	0.08	0.14	0.04

Table 1 - Average and maximum chloride content by fuel type for laboratory tests from 2005 to 2013

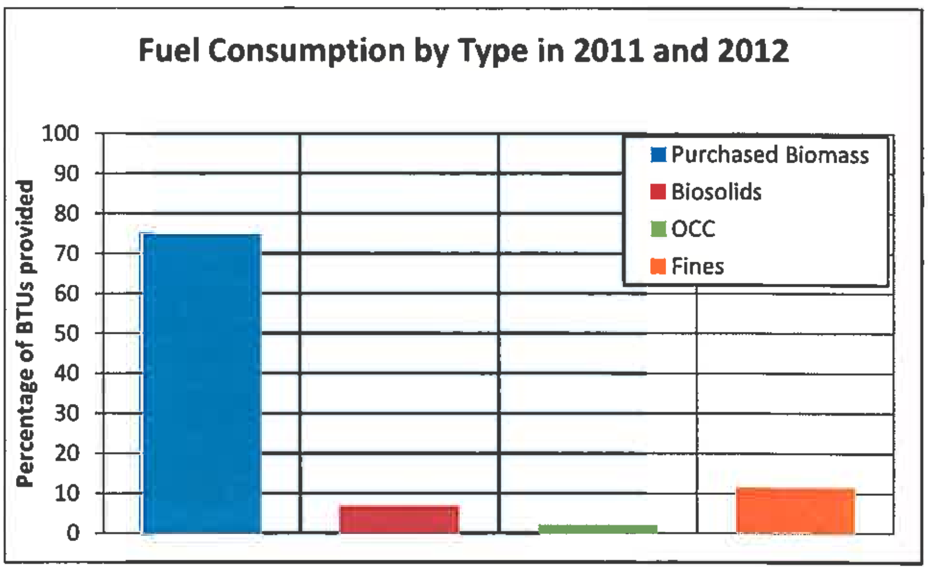

Figure 2 - Fuel Consumption by Type on a percent BTU basis for 2011 and 2012. The percentages do not add up to 100% as natural gas (approximately 5%) was not shown in this graph.

STK Fuel Chloride Loading Comparison to BMACT Data

A review of the data from the EPA Boiler MACT emissions database Technical Support Documents (http://www.epa.gov/ttn/atw/boiler/boilerpg.html) reveals that Simpson Tacoma Kraft is unique in the level of chlorides in the fuel. While Simpson did not submit specific fuel chloride test results to the EPA for Boiler MACT, shown on Figure 2 is where the historical average fuel test results would have placed the boiler. Over 63 fuel chloride tests (total fuel feed to the boiler, not individual fuel types) were averaged and multiplied by the average bone dry tons per hour of fuel feed to get the 48 lbs/hr of chloride to the boiler, near the top for all biomass boilers in the database.

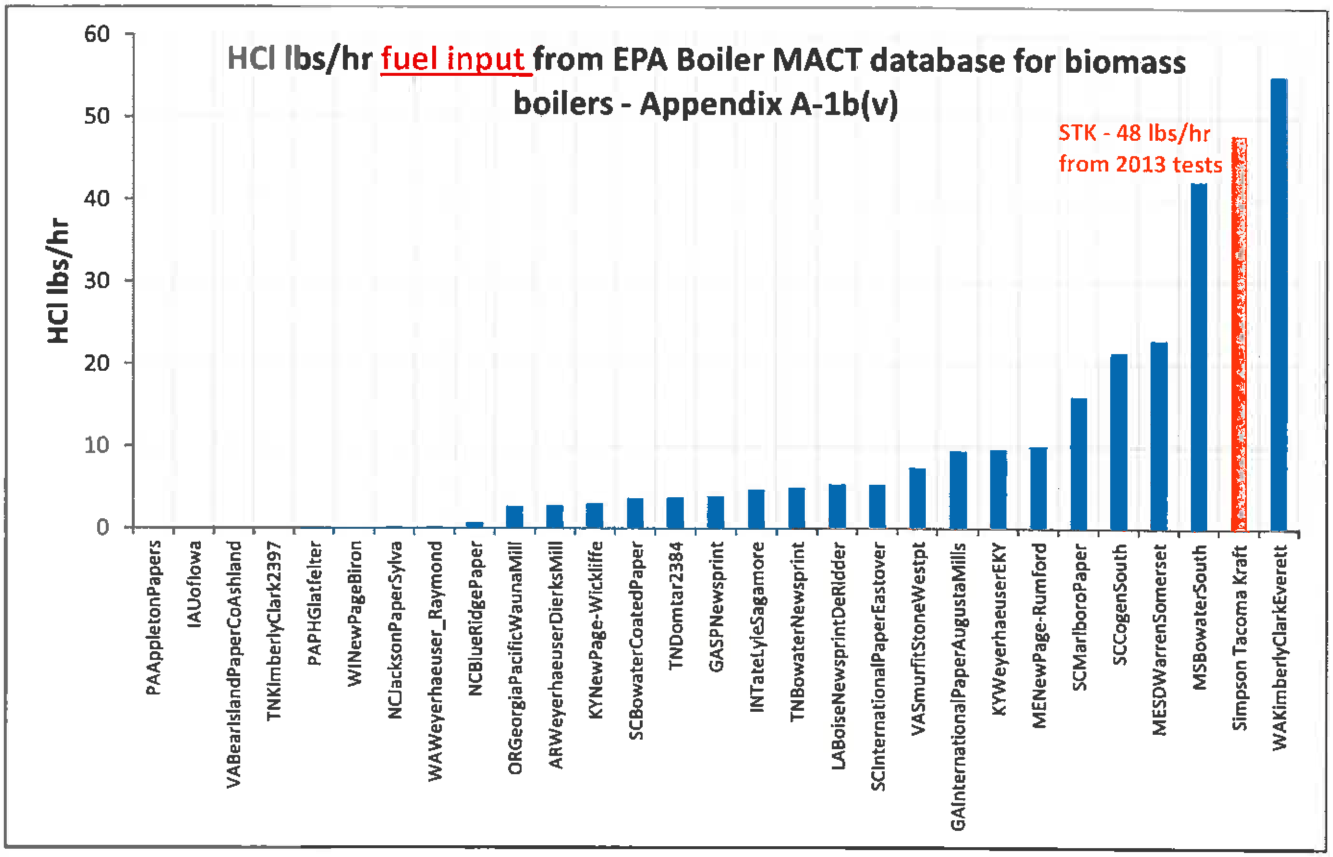

Figure 3 - STK placement on HCl lbs/hr from EPA database. Averaged Column G (Calc HCl – lbperhour) from Appendix A-1b(v): Chlorine Fuel Input Calculation for Multi-fuel Units. Data source: Dec 2011 MACT Floor Analysis for Major Source Boilers and Process Heaters. 48 lbs/hr based on 900 ppm Cl fuel input @ 26 BDTPH fuel feed

Summary

- STK uses a number of fuels in PB7, whose chloride content are relatively high and varies
- STK fuel testing results show dewatered biosolids have, on average, the highest chloride content, although some individual samples of purchased biomass also showed notably high chloride content
- STK has tested intensively a number of fuels in an attempt to find a fuel supply meeting Boiler MACT limits but has not been successful
- Comparing HCl fuel input at STK to units in the Boiler MACT database shows that STK lb/hr fuel input is higher than all but one boiler in the database.

Predicted NH4Cl Emissions at a constant HCl Emission rate and varied NH3 slip

In the following graphic HCl emissions were held constant at 8ppm while ammonia slip was varied. Potential maximums of ammonium chloride emissions are presented assuming complete reaction between all available NH3 and HCl. Once the HCl has been completely consumed, additional slip is presented as gaseous ammonia emissions.

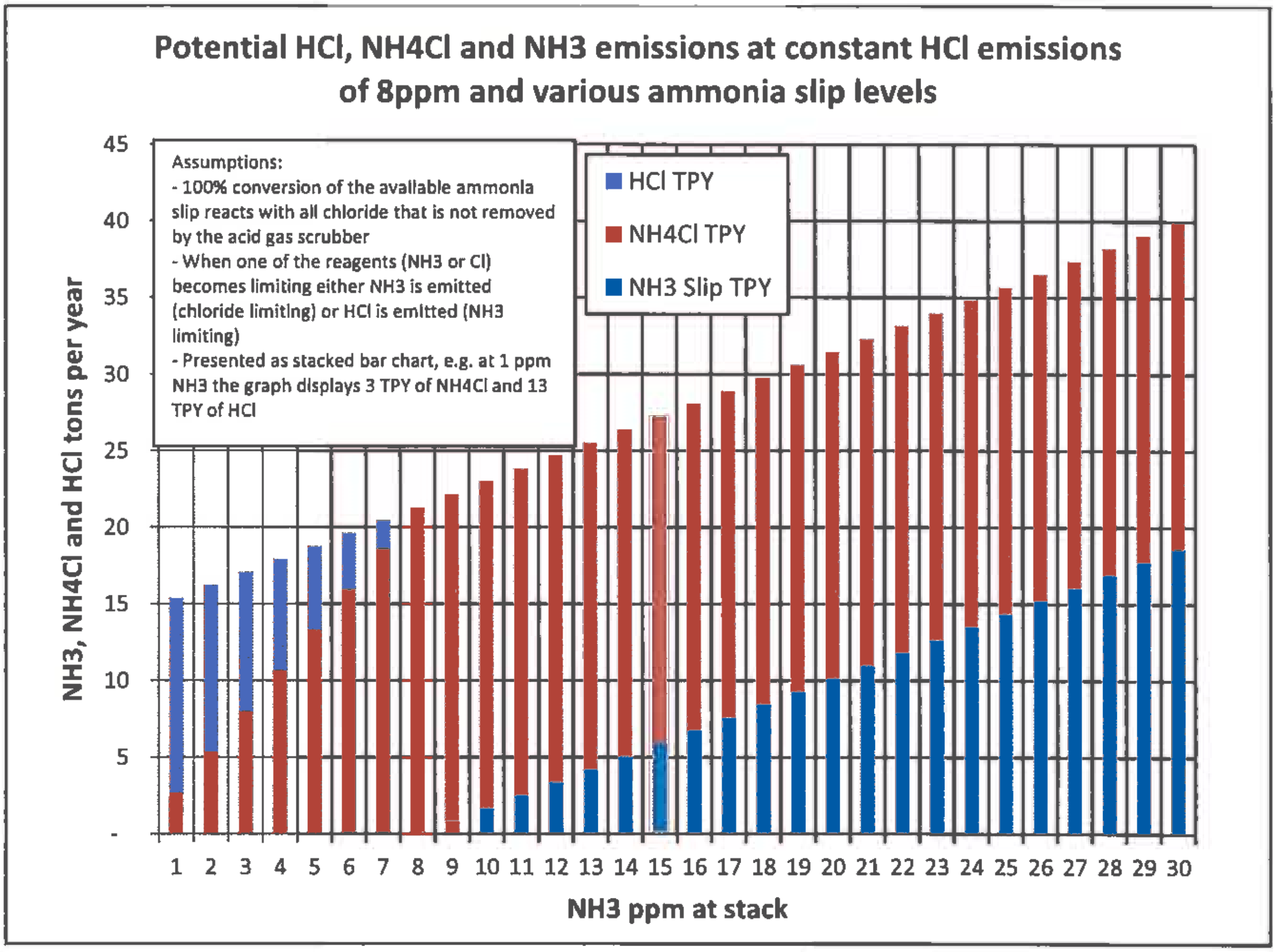

Figure 4 - Predicted NH4Cl emissions at a constant HCl emission rate and varied NH3 slip.

This graphic displays potential HCl, NH4Cl and NH3 emissions when ammonia slip is held constant and HCl at the stack is varied.

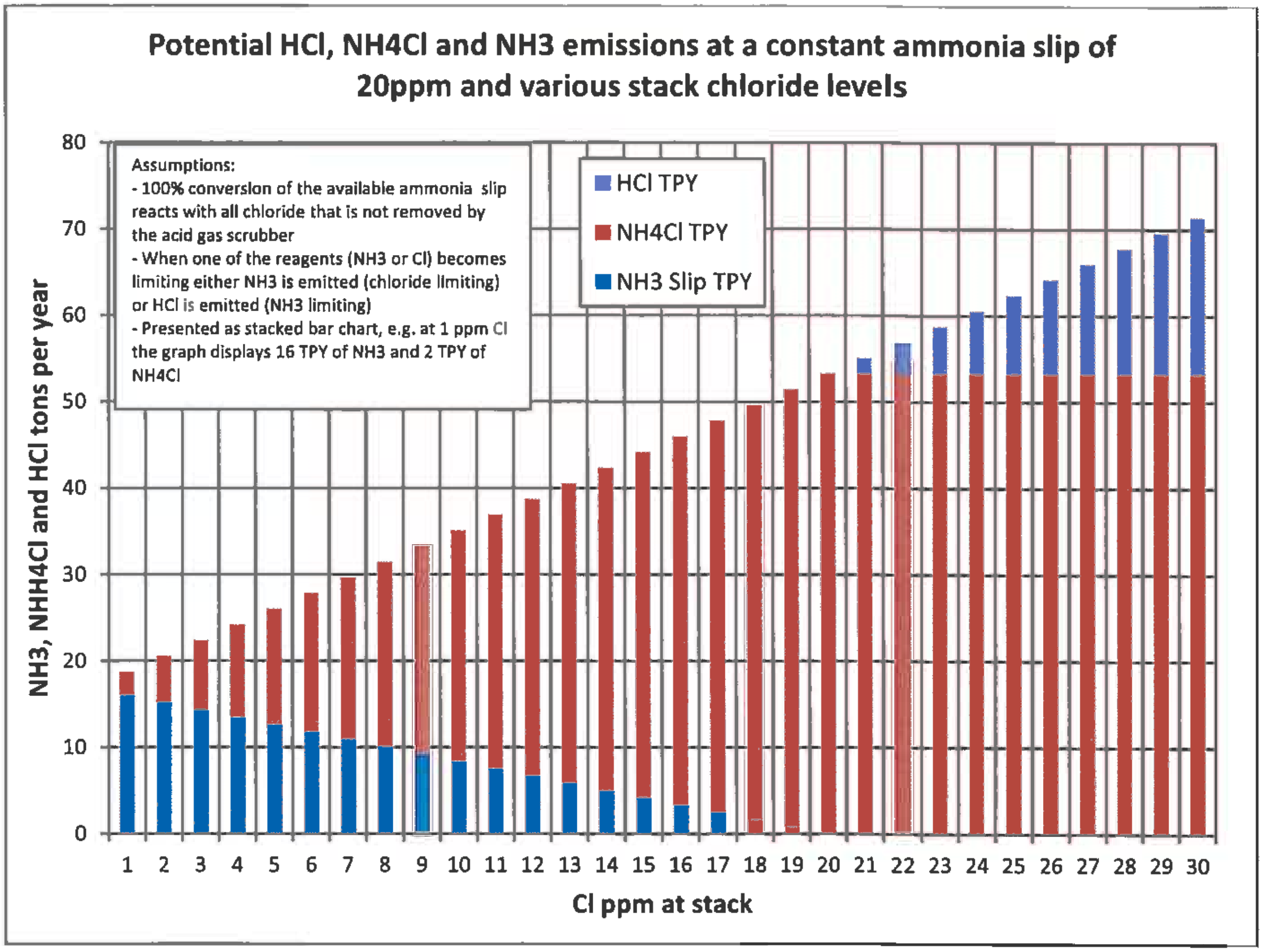

Figure 5 - Predicted NH4Cl emissions at a constant NH3 slip and varied HCl emission rate.

2013 Fuel Chloride Test Results

STK did fuel testing during the trials in the summer of 2013 and the summary of results is in the table below. STK did not analyze fuel during the trials in February 2014.

2013 Fuel Chloride Test Results	Average mg/kg Cl	Average lb HCl/MMBtu
(2013) C&D #1	519	0.067
(2013) C&D #2	525	0.067
(2013) C&D #3	247	0.029
(2013) Land Clearing	318	0.042
(2013) Bark	367	0.038
(2013) Sludge and Fines	(1)	(1)
(2013) Urban Wood (C&D)	362	0.043
(2013) Pallets	320	0.037
(1) - Did not test the combined sludge and fines on the belt. Only tested individual fuel streams. Sludge = 428 ppm, 0.058 lb/MMBtu. Fines = 784 ppm, 0.089 lb/MMBtu		

The results of the individual tests are as follows:

Date	Fuel Type	Testing Location	Cl, mg/kg	BTU/lb	lb Cl / MMBtu
7/18/2013	C&D #1 Belt Test #1	Fuel Belt	523	7930	0.066
7/18/2013	C&D #1 Belt Test #2	Fuel Belt	537	7930	0.068
7/18/2013	C&D #1 Truck Sample	Hog Suppliers	383	7910	0.048
7/18/2013	C&D #1 Truck Sample	Hog Suppliers	417	7910	0.053
7/18/2013	Fines	Fines	784	8830	0.089
7/18/2013	Sludge	Sludge - Dewatered	428	7320	0.058
7/18/2013	OCC	OCC	163	11390	0.014
7/30/2013	C&D #3 Belt Test #1	Fuel Belt	220	8480	0.026
7/30/2013	C&D #3 Belt Test #2	Fuel Belt	251	8480	0.030
7/30/2013	C&D #3 Belt Test #3	Fuel Belt	270	8480	0.032
7/30/2013	C&D #3 Truck Sample	Hog Suppliers	276	8480	0.033
7/25/2013	C&D #2 Belt Test #3	Fuel Belt	605	7840	0.077
7/25/2013	C&D #2 Belt Test #4	Fuel Belt	445	7840	0.057
7/25/2013	C&D #2 Truck Sample	Hog Suppliers	407	7650	0.053
7/25/2013	C&D #2 Truck Sample	Hog Suppliers	338	7650	0.044
8/3/2013	Bark Belt Test #1	Fuel Belt	455	8810	0.052
8/3/2013	Bark Belt Test #2	Fuel Belt	237	8810	0.027
8/3/2013	Bark Belt Test #3	Fuel Belt	309	8810	0.035
8/3/2013	Bark Supplier #1 Truck Sample	Hog Suppliers	27	9590	0.003
8/3/2013	Bark Supplier #2 Truck Sample	Hog Suppliers	34	8900	0.004
8/2/2013	Land Clearing Belt	Fuel Belt	196	7600	0.026

Date	Fuel Type	Testing Location	Cl, mg/kg	BTU/lb	lb Cl / MMBtu
	Test #1				
8/2/2013	Land Clearing Belt Test #2	Fuel Belt	439	7600	0.058
8/2/2013	Land Clearing Supplier #1 Truck Sample	Hog Suppliers	121	7290	0.017
8/2/2013	Land Clearing Supplier #2 Truck Sample	Hog Suppliers	25	5300	0.005
8/2/2013	Land Clearing Supplier #3 Truck Sample	Hog Suppliers	44	9190	0.005
8/7/2013	Urban Wood Supplier #1 Truck Sample	Hog Suppliers	475	8750	0.054
8/7/2013	Urban Wood Supplier #2 Truck Sample	Hog Suppliers	394	8710	0.045
8/7/2013	Urban Belt Test #1	Fuel Belt	346	8510	0.041
8/7/2013	Urban Belt Test #2	Fuel Belt	338	8510	0.040
8/7/2013	Urban Belt Test #3	Fuel Belt	403	8510	0.047
8/9/2013	Pallet Truck Sample	Hog Suppliers	178	8510	0.021
8/9/2013	Pallet Belt Test #1	Fuel Belt	232	8540	0.027
8/9/2013	Pallet Belt Test #2	Fuel Belt	407	8540	0.048
8/10/2013	C&D #4 Truck Sample	Hog Suppliers	359	8220	0.044
8/10/2013	C&D #4 Belt Test #1	Fuel Belt	314	8240	0.038
8/10/2013	C&D #4 Belt Test #2	Fuel Belt	396	8240	0.048
8/10/2013	C&D #4 Belt Test #3	Fuel Belt	3146	8240	0.382

STK wishes to make the following notes regarding the table.

The "urban wood" category above is also mostly C&D. This category exists to address a few loads received from small local suppliers, as opposed to the larger fuel companies.

The C&D #4 run tested in the summer of 2013 was an outlier and excluded from this table.

The chloride concentration in the 2013 trials is lower than what was typical from STK's historical data set, which presents an average around 900 mg/kg. STK is unsure as to why; to its knowledge there has not been any change in the general nature of its fuel supply.

The 2013 testing was focused on stack emissions. Consequently, the fuel sampling was via grabs, and STK did not perform a formal compositing method. That said, in many cases STK took grabs from the truck and from the belt for the same fuel, so it provides a type of a composite.

Regarding 2013 emissions data, STK rented a portable FTIR. STK did daily cal gas challenges (for drift checks), and a RATA as well, as STK was skeptical of the results. A similar protocol was followed in February 2014, except STK did not do a RATA then.

The following are the reasons why STK doubted the summer 2013 stack test results. STK observed that they were essentially at the BMACT limit while burning natural gas only. Second, STK found that the fuel chloride mass loading rate was, in multiple instances, lower than the stack mass emission rate. STK theorized that chloride accumulated in the ash within the boiler system was being displaced by sulfur dioxide. Accordingly, STK performed the emissions trials again in February 2014 when the boiler was coming out of a planned maintenance outage (clean system) and ran the trials for much longer (~12-24+ hours each fuel type). STK thought this would give time for any ash effects to stabilize. The February testing showed that, even with longer trial times and a clean boiler, STK could not get below the boiler MACT limit.

APPENDIX E

APPENDIX E
TACOMA MILL POWER BOILER NO. 7
SUPPLEMENT TO THE NO_x BACT ANALYSIS

I. BACKGROUND

In 2006, Simpson Tacoma Kraft Company, LLC (Simpson) submitted an application to the Washington Department of Ecology (Ecology) for a permit to construct a 55 MW steam turbine generator, modify Power Boiler No. 7 (PB-7), and implement certain other changes at the Tacoma, Washington pulp and paperboard mill to generate biomass, or "green", electric power for sale to the grid (collectively, the "Cogeneration Project"). Simpson determined that the Cogeneration Project would trigger Prevention of Significant Deterioration (PSD) permitting for three pollutants: NO_x, CO, and PM_{10}. Simpson's BACT analysis for NO_x was based on combustion system improvements for PB-7; specifically, the installation of an over-fired air (OFA) system. On May 22, 2007, Ecology issued Simpson a PSD permit for the Cogeneration Project (PSD-06-02). This permit included a BACT NO_x emission limit for PB-7 of 0.2 lb/MMBtu on a 30-day rolling average and an annual NO_x limit of 522 tons per year (tpy) based on the presumed NO_x emissions performance of the OFA system.

Upon commencing operation of the Cogeneration Project, Simpson discovered that PB-7 was unable to achieve the 0.20 lb/MMBtu NO_x emission limit on a 30-day rolling average and reported the situation to Ecology in January 2010. In March 2010, Simpson requested that Ecology revise the short-term and annual NO_x emission limits for PB-7 on the basis that these limits were based on erroneous assumptions about the degree of NO_x control achievable with the OFA system. Simpson and Ecology subsequently entered into Agreed Order 7688, in which Ecology agreed to process Simpson's PSD permit revision request without delay, provided that Simpson (1) expeditiously respond to any request for additional information needed by Ecology to process the PSD amendment application, and (2) operate PB-7 in a manner so as to minimize NO_x emissions and comply with the other conditions in PSD-06-02.

In August 2010, Simpson submitted additional information to Ecology in support of its request to revise PSD-06-02 to change the short-term NO_x emission limit for PB-7 from 0.20 lb/MMBtu to 0.30 lb/MMBtu and the annual limit from 522 tpy to 782 tpy. Ecology prepared a draft amendment to PSD-06-02 in response to Simpson's request and sent the package to U.S. EPA Region 10 for review.

As part of EPA's review, in 2014 EPA requested that the Tacoma Mill[1] evaluate the cost effectiveness of add-on NO_x control in combination with add-on control for hydrogen chloride (HCl) to supplement the BACT analysis originally performed by Simpson in 2006 and re-analyzed in 2010. This document provides the economic analysis of concurrent NOx and HCl control requested by the USEPA.

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[1] RockTenn CP, LLC purchased the Tacoma Mill from Simpson on May 16, 2014; however, Simpson has retained all obligations and liabilities arising from or relating to the PB-7 NO_x compliance issues described above.

Analysis of a combined control configuration was requested because the PB-7 biomass fuel supply presents relatively high HCl emissions, and it is well established that chloride in flue gas will react with unreacted ammonia from NO_x control technologies (SCR or SNCR) to form ammonium chloride (NH_4Cl), which is a fine particulate that can impact regional air quality and cause a severe persistent visible plume. Given the profound issues regarding NH_4Cl formation when SCR or SNCR are used with a high chloride flue gas, the cost basis used for evaluating add-on NO_x control in the BACT process should also include the cost of control for HCl.

While add-on HCl control will be installed on PB-7 to facilitate compliance with the Boiler MACT (40 CFR part 63 subpart DDDDD), the issue at hand is review of a NO_x BACT limit established via a permit issued in 2007. Accordingly, the configuration of the boiler contemplated during this permitting (no add-on HCl control installed or required) is the proper basis for the present economic analysis and BACT reconsideration.

II. OVERVIEW

PB-7 is a Riley Stoker combination fuel boiler that was installed at the Tacoma Mill in 1990 and modified in 2009 as part of the Cogeneration Project. The boiler is rated at 595 MMBtu/hr heat input and 340,000 lb/hr steam, and primarily fires biomass. It also has the capability to fire natural gas or oil as backup fuel. Particulate matter (PM) emissions are controlled with multiclones and a dry electrostatic precipitator (ESP) manufactured by Research-Cottrell.

Recent and historical fuel analysis indicates that the biomass fuel supply for PB-7 has unusually high chloride levels when compared to other operating biomass boilers (EPA's Boiler MACT emissions database (Technical Support Documents (http://www.epa.gov/ttn/atw/boiler/boilerpg.html)). Historical reference method testing and more recent intensive testing with an HCl continuous emissions monitoring system has consistently found relatively high chloride levels in the flue gas.

Due to the unusually high chloride levels in the flue gas of PB-7, and the inevitable presence of ammonia slip generated from add-on NO_x control (SCR or SNCR) if it was installed and operated, a very substantial reduction of chlorides to below 5 ppm (92+% control) (or limitation of ammonia slip to below 5 ppm following ammonia injection) would be necessary to minimize the emissions of NH_4Cl $PM_{2.5}$ particulate and formation of a persistent visible plume. To the extent the only available and nominally cost effective biomass boiler NO_x control technologies involve ammonia injection and the NOx control effectiveness is minimal at ammonia slip levels below 5 ppm, it would be necessary to concurrently control HCl when using add-on NOx control on PB-7.

To analyze the economic cost of concurrently controlling NO_x and HCl on PB7, a control technology feasibility review was conducted and the costs of feasible technologies was estimated. To the extent this is a supplement to previously submitted BACT analyses and the aspects of those previous analyses relevant to NO_x control have not changed, this analysis focuses on HCl control feasibility and cost. SNCR was chosen as the reference NO_x control technology for the analysis and the cost and performance data submitted previously are used (August 2010). SCR is not included in the present analysis because it's utilization on biomass boilers is not mature, and costs are significantly greater than SNCR due to the high cost of catalyst and high operating costs due to fouling and the need for catalyst heating. Data provided by Jansen Engineering indicate that SCR suitable for PB-7 would likely present ammonia slip greater than 5 ppm; HCl control would be required. Additionally, SNCR is less expensive than SCR and thereby presents a more conservative cost analysis.

IV. COST ANALYSIS OF CONCURRENT NOx AND HCl CONTROL

STEP 1 - IDENTIFY ALL POTENTIAL CONTROL TECHNOLOGIES

The following HCl control technologies are considered in this analysis:

- Dry Sorbent Injection (DSI) with trona (a sodium carbonate mineral),
- Spray Dry Absorption (SDA) with caustic, and
- Wet Scrubbing System with caustic.

<u>Dry Sorbent Injection</u>

In DSI systems, finely divided sodium or calcium based minerals are injected into the boiler exhaust gases upstream of a particulate matter collection device. The injected material absorbs the acid gases on the surface of the particles, the acid gases react with the calcium or sodium compounds, and the particles are collected. DSI systems are suitable for biomass boiler acid gas controls, and experience has resulted in biomass boiler DSI systems favoring the use of sodium chemicals. Both trona (sodium sesquicarbonate) and sodium bicarbonate are used as sorbents in DSI systems. Trona is the raw material mined and calcined to produce commercial sodium bicarbonate and sodium carbonate. The price of the three chemicals reflects the amount of processing done at the mine mouth, so trona is the cheapest.

Trona does not require milling as received, although milling does allow for more efficient use of the sorbent. An above stoichiometric quantity of trona is required for high acid gas removal efficiency. For this application, approximately 1,100 lb/hr of trona is assumed necessary to achieve the desired acid gas control efficiency, which will need to be collected by a particulate control device.

<u>Spray Dry Absorption</u>

In SDA systems, the flue gases are introduced into an absorbing tower (dryer) where the gases are contacted with a finely atomized alkaline slurry or solution (usually a calcium-based sorbent such as $Ca(OH)_2$ or CaO, or a sodium-based chemical such as NaOH). Acid gases are absorbed by the slurry mixture, and react to form solid salts. The heat of the flue gas is used to evaporate all the water droplets leaving a non-saturated (i.e. dry) flue gas exiting the absorber tower. The effect of cooling and humidifying the hot gas stream increases collection efficiency over simple dry injection. Ample reaction sites and time must be present in the tower, and the solid reaction products must be removed from the gas stream through use of a particulate control device. Typical reaction vessels for an application like PB-7 are 18 feet in diameter and 65 feet high, providing 5-10 seconds of residence time.

Spray dryer absorbers are effective at removing acid gases, but do have disadvantages. The injection and atomization equipment required is much more complicated and expensive to operate than DSI. As with DSI systems, the actual use of sorbent necessary for high acid gas removal will be above the stoichiometric quantities because of normal inefficiencies in operation.

Wet Scrubbing

Wet scrubbers follow one of several design principles: packed towers, plate or tray columns, venturi scrubbers, and spray chambers.

Packed towers are columns filled with packing materials that provide a large surface area to facilitate contact between the liquid and gas. Packed tower scrubbers can achieve higher removal efficiencies, handle higher liquid rates, and have relatively lower water consumption requirements than other types of gas scrubbers. However, they may also have high system pressure drops, high clogging and fouling potential, and extensive maintenance costs due to the presence of packing materials.

Plate or tray towers are vertical cylinders in which the liquid and gas are contacted in a stepwise fashion on trays or plates. Plate towers are easier to clean and tend to handle large temperature fluctuations better than packed towers. However, at high gas flow rates, plate towers exhibit larger pressure drops and have larger liquid holdups.

Venturi scrubbers have been generally applied for controlling particulate matter and sulfur dioxide. A venturi scrubber employs a gradually converging and then diverging section, called the throat, to clean incoming gaseous streams. Liquid is either introduced to the venturi upstream of the throat or injected directly into the throat where it is atomized by the gaseous stream. Once the liquid is atomized, particles in the exhaust gas are collected and gaseous pollutants may be absorbed. The droplets are usually removed in a centrifugal separator followed by a demister. Venturi scrubbers tend to have a high pressure drop resulting in high energy use and the relatively short gas-liquid contact time restricts their application to highly soluble gases.

Spray towers operate by delivering liquid droplets through a spray distribution system. The droplets fall through a countercurrent gas stream under the influence of gravity and contact the pollutants in the gas. Spray towers are simple to operate and maintain, and have relatively low energy requirements. However, they have the least effective mass transfer capability of the scrubbers discussed and are usually restricted to particulate matter removal and control of highly soluble gases. They also require higher water recirculation rates.

Any wet scrubber installed on PB-7 would be downstream of the existing ESP and a wet plume would be emitted. Solids produced from reactions of the absorbent and the acid gases would be incremental PM emissions. All scrubber systems would have some type of circulating water system that would have to be operated within a given pH range, along with an upper limit on the suspended solids concentration. There would be a "blow-down" stream with a solids content that would need to be managed as well.

Impact on Current Particulate Matter Controls (Dry ESP)

PB-7 is currently equipped with a dry electrostatic precipitator (ESP). Because of the level of HCl abatement necessary to facilitate NO_x control on PB-7, both the DSI and SDA control options would require large quantities of reagent and would substantially increase particulate loading to the ESP. This would compel either installation of additional particulate matter (PM) control on PB-7 (such as a baghouse) or an upgrade of the existing ESP to handle the substantial increase in particulate loading.

Due to the number of variables affecting loading and collection, it is difficult to predict the extent of upgrades to the ESP that would be necessary to handle increased particulate loading from a DSI system controlling HCl to the necessary levels. It is likely that it would not be possible to sufficiently retrofit or modify the existing ESP. Nevertheless, for completeness, a cost scenario is provided for DSI and an upgraded ESP.

ESP upgrade scenarios are not provided for SDA because SDA does not improve the collectability of the PM formed, and SDA can present a wet flue gas. These factors make a dry ESP nearly incompatible with SDA. In addition, SDA is more expensive than DSI, and DSI, therefore, presents a more conservative cost expression.

The ESP upgrade cost estimate included in this supplement assumes that only straightforward mechanical and electrical system upgrades would be necessary to allow the ESP to handle the additional loading and maintain compliance with existing particulate emission limits. If the ESP did require an expansion or other extraordinary mechanical or electrical modifications, the cost would significantly increase.

Additional Particulate Matter Control for Wet Scrubber System

Although a wet scrubber system would be able to control acid gases from PB-7, it is unknown whether a wet scrubber would provide the level of HCl abatement necessary in this specific case to avoid formation of a non-compliant visible plume and significant

$PM_{2.5}$ emissions[2]. The quenching effect of the scrubber would, in all likelihood, cool the flue gas enough to form a significant amount of NH_4Cl before the scrubber system has the opportunity to adequately limit the formation of the NH_4Cl (through HCl or ammonia capture). Because scrubber technology is not very effective at collecting fine particulate, the NH_4Cl would pass through the scrubber and produce particulate emissions and a visible plume. The pressure drop required by a wet scrubber for control of sub-micron size particles is too high to be practical. In order to remove these particles, the wet scrubber system would need to be followed by a Wet Electrostatic Precipitator (WESP). Therefore, a wet scrubber with a WESP is a cost scenario evaluated in this analysis.

STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Although the above control options have not been demonstrated in practice in an application with such an extreme chloride level concurrent with normal ammonia slip from SNCR, the control options are assumed to be technologically feasible for this analysis[3].

STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES

The technologically feasible control options to be installed along with SNCR are provided in Table 1, along with associated emission reduction potentials.

TABLE 1. CONTROL TECHNOLOGY AND CONTROL EFFECTIVENESS

CONTROL TECHNOLOGY	HCL REMOVAL EFFICIENCY (%)
SNCR + DSI + Baghouse	90%+
SNCR + DSI + Upgraded ESP	90%+
SNCR + SDA + Baghouse	90%+
SNCR + Wet Scrubber + WESP	90%+

Note that these combinations of controls must be able to achieve: (1) adequate control of NO_x emissions, (2) adequate control of chloride emissions, (3) maintain compliance with particulate matter emission limits, and (4) minimize emissions of NH_4Cl and avoid the formation of an NH_4Cl plume. Any period with a loss of HCl control, however brief, has the potential to create a short-term visible plume and particulate emission limit exceedance, even though long-term emission limits are being maintained.

[2] Ammonia and chloride in flue gas form NH_4Cl at lower temperatures (~ <250 °F). As temperature drops across the scrubber, there may be significant solids formation prior to adequate capture of chloride (or ammonia). The RockTenn Mill at Tacoma is located in a $PM_{2.5}$ nonattainment area.

[3] Based on the proposal from Fuel Tech on July 30, 2010, as well as an evaluation of control technology by AMEC on July 23, 2014, it is assumed that this series of control technology is technically feasible. However, until trials and computational fluid dynamics (CFD) modeling can be performed, there is much uncertainty related to the injection points of ammonia and sorbent, the quantity of sorbent required, and the fluctuating temperatures and CO levels of the boiler (which will affect NO_x reduction efficiency). Additionally, trials would need to be conducted with trona injection to determine the ability of the ESP to handle the substantial increase in particulate loading. Due to these uncertainties, it cannot be stated with complete confidence that the series of control technologies presented is technically feasible.

STEP 4 - EVALUATE THE MOST EFFECTIVE CONTROLS

The economic and environmental impact of the technologically feasible control options are discussed below.

ENVIRONMENTAL IMPACTS

Due to the unusually high chloride levels in the flue gas of PB-7, the inevitable presence of ammonia slip generated from add-on NO_x control, and the impossibility of 100% reaction and collection rates, some additional NH_4Cl $PM_{2.5}$ would be emitted and would impact regional air quality if add-on NO_x control is utilized. These additional NH_4Cl emissions present a significant negative environmental impact because the Tacoma area is currently nonattainment for $PM_{2.5}$. Also note that ammonia itself is a $PM_{2.5}$ precursor and is undesirable in the nonattainment area.

The wet scrubber / WESP option presents contaminated wastewater flow and solids. The DSI and SDA options present additional ash volume.

ENERGY AND OTHER IMPACTS

Additional energy consumption would result from operation of each of the control options presented. DSI would require blowers to convey the dry sorbent and a mill would be necessary to prepare the material for injection. SDA and a wet scrubber / WESP each require pumping of the liquid scrubbing medium, and would present additional water use. The additional PM load to an upgraded ESP would result in higher energy use. An additional fan must be installed and operated in the case of a baghouse or a wet scrubber/WESP.

COST EFFECTIVENESS

SNCR in combination with each of the HCl control options listed above has been evaluated for cost effectiveness. The baseline NO_x emission rate is conservatively selected as 0.30 lb/MMBtu, based on the emission limits proposed in the amendment application. Baseline annual NO_x emissions, using the 0.30 lb/MMBtu rate, are estimated at 781.8 tons per year (tpy).

Based on the information provided by Fuel Tech, SNCR with a 5 ppm ammonia slip can achieve a NO_x emission rate of 0.23 lb/MMBtu (but this performance was not guaranteed). It is estimated that the current NO_x emission limit of 0.20 lb/MMBtu can be achieved with an ammonia slip between 5 and 20 ppm. Reducing NO_x emissions from 0.30 lb/MMBtu to 0.20 lb/MMBtu would result in a NO_x reduction of 260.6 tpy.

A summary of capital costs for the three control options, which were provided by AMEC on July 23, 2014, are summarized in Table 2.

TABLE 2. CAPITAL COST SUMMARY

Control Options		Total Equipment Costs	Direct Installation Costs	Indirect Installation Costs
1	SNCR + DSI + Baghouse	$7,500,000	$9,000,000	$5,500,000
	SNCR + DSI + Upgraded ESP	$5,000,000	$5,000,000	$5,000,000
2	SNCR + SDA + Baghouse	$10,000,000	$12,000,000	$10,000,000
3	SNCR + Wet Scrubber + WESP	$8,500,000	$9,580,000	$9,000,000

Using the baseline of 0.30 lb/MMBtu NO_x, the cost effectiveness of control options to achieve a NO_x emission rate of 0.20 lb/MMBtu are provided in Table 3. Note that these costs are conservative estimations because the analysis did not account for the costs associated with onsite demolition, retrofitting of equipment, and the additional footprint required for the proposed control options. The costs presented in Table 3 are significantly above that which would be considered cost effective. Therefore, the above control options are not economically feasible. Detailed cost calculations are shown in Attachment 1.

TABLE 3. COST EFFECTIVENESS SUMMARY

CONTROL OPTIONS		COST EFFECTIVENESS ($ PER TON OF NO_X CONTROL)
1	SNCR + DSI + BAGHOUSE	$20,300
	SNCR + DSI + UPGRADED ESP	$16,300
2	SNCR + SDA + BAGHOUSE	$24,100
3	SNCR + WET SCRUBBER + WESP	$20,300

SELECT BACT

In the August 2010 NO_x BACT re-analysis submittal to Ecology, the Tacoma Mill concluded that 0.30 lbs NO_x per mmBtu, rolling 30-day average, is the appropriate BACT limit for PB-7. This proposed BACT limit properly reflects the performance of the technology selected in the BACT analysis by Ecology when the PSD permit was issued.

NO_x emissions consistently lower than 0.30 lbs/mmBtu would require add-on NO_x control. The only available and nominally cost effective add-on NO_x control technologies involve ammonia injection. In the case of PB-7, concurrent and rigorous control of HCl emissions would be necessary to facilitate use of ammonia injection for NO_x control. This analysis demonstrates that the cost of concurrent NO_x and HCl control is not economically feasible and it confirms that 0.30 lbs/mmBtu is the correct BACT NO_x limit for PB-7.

Attachment 1:
Cost Calculations

Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + DSI + Baghouse

TABLE E-1 - CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. SNCR	$1,500,000	AMEC database[1]
b. DSI System	$2,500,000	AMEC
c. Baghouse	$3,500,000	AMEC
Total Purchased Equipment Cost [TEC]	$7,500,000	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports	$810,000	AMEC
b. Site Prep/Equipment Foundation	$135,000	AMEC
c. Electrical	$540,000	AMEC
d. Piping/Ductwork	$2,655,000	AMEC
e. Installation	$4,860,000	AMEC
Total Direct Costs [TDC](I+II)	$16,500,000	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering	$2,600,000	AMEC
b. Owner Engineering	$1,100,000	AMEC
Total Direct and Indirect Costs [TDIC](I+II+III)	$20,200,000	*Calculation*
Contingency	$1,400,000	AMEC
Operator Training	$200,000	AMEC
Startup	$200,000	AMEC
Total Capital Costs [TCC] (TDIC + Contigency + Training + Startup)	$22,000,000	*Calculation*
Total Annualized Capital Costs [TACC] (15 years @ 8.5% interest)	**$2,649,250**	*Calculation*

(1) Data from the AMEC database, based on similar projects, in-house data, and experience with new installations and retrofits.

Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + DSI + Baghouse

TABLE E-2 - DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS FOR SNCR		**Cost**	**Source**
I. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
III. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
IV. Replacement Parts (100% of maintance labor)		$27,375	OAQPS
V. Utility costs (none)			
VI. Ammonia (NOxOut®) = (34 gal/hr)*24*365*($2.07/gal)		$616,529	Fuel Tech
Subtotal for SNCR:		$699,612	*Calculation*
DIRECT OPERATING COSTS FOR DSI/BAGHOUSE			
VII. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
VIII. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
IX. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
X. Replacement Parts (100% of maintenance labor)		$27,375	OAQPS
XI. Trona = (1,100 lbs/hr)*(24*365)($200/ton)*(1 ton/2,000lb)		$963,600	Vendor Estimate/Harris Group
XII. Disposal = (1,100 lbs/hr)*(24*365)*($25.96/ton)*(1 ton/2,000 lb)		$124,064	Engineering Estimate/Harris Group
XIII. Electricity: = ($0.036/kW-hr)(8,760 hr/yr)(60 hp)(0.7457 kW/hp)/(0.70 efficiency)		$20,157	Engineering Estimate/Harris Group
Subtotal for DSI:		$1,190,904	*Calculation*
DIRECT OPERATING COSTS (DOC) - Sum of SNCR and DSI Costs:		$1,890,515	*Calculation*
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs)		$99,700	OAQPS
IX. Administration (0.02*TCC)		$440,000	OAQPS
X. Insurance (0.01*TCC)		$220,000	OAQPS
Subtotal for Indirect Costs:		$759,700	*Calculation*
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		**$2,650,215**	*Calculation*
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)		**$5,299,465**	*Calculation*
Boiler Heat Rate (MMBtu/hr)		**595**	*Design*
Normalized Stoichiometric Ratio (NSR)		**1.3**	*Fuel Tech*
NOX baseline emissions (0.30 lb/MMBtu)	tons/year	781.8	*Calculation*
NOX emissions w/ SNCR (0.20 lb/MMBtu)	tons/year	521.2	*Calculation*
Reduction from baseline	Percent	33.3	*Calculation*
Total Emissions Reduction	tons/year	260.6	*Calculation*
Cost per ton Conrolled	***$/ton***	**$ 20,335**	*Calculation*

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Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + DSI + ESP Upgrade

TABLE E-3 - CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. SNCR	$1,500,000	AMEC database[1]
b. DSI System	$2,500,000	AMEC
c. ESP Upgrade	$1,000,000	AMEC
Total Purchased Equipment Cost [TEC]	$5,000,000	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports	$630,000	AMEC
b. Site Prep/Equipment Foundation	$76,000	AMEC
c. Electrical	$502,000	AMEC
d. Piping/Ductwork	$992,000	AMEC
e. Installation	$2,800,000	AMEC
Total Direct Costs [TDC](I+II)	$10,000,000	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering	$2,500,000	AMEC
b. Owner Engineering	$1,000,000	AMEC
Total Direct and Indirect Costs [TDIC](I+II+III)	$13,500,000	*Calculation*
Contingency	$1,250,000	AMEC
Operator Training	$150,000	AMEC
Startup	$100,000	AMEC
Total Capital Costs [TCC] (TDIC + Contigency + Training + Startup)	$15,000,000	*Calculation*
Total Annualized Capital Costs [TACC] (15 years @ 8.5% interest)	**$1,806,307**	*Calculation*

(1) Data from the AMEC database, based on similar projects, in-house data, and experience with new installations and retrofits.

Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + DSI + ESP Upgrade

TABLE E-4 - DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS FOR SNCR		**Cost**	**Source**
I. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
III. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
IV. Replacement Parts (100% of maintance labor)		$27,375	OAQPS
V. Utility costs (none)			
VI. Ammonia (NOxOut®) = (34 gal/hr)*24*365*($2.07/gal)		$616,529	Fuel Tech
Subtotal for SNCR:		$699,612	*Calculation*
DIRECT OPERATING COSTS FOR DSI/BAGHOUSE			
VII. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
VIII. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
IX. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
X. Replacement Parts (100% of maintenance labor)		$27,375	OAQPS
XI. Trona = (1,100 lbs/hr)*(24*365)($200/ton)*(1 ton/2,000lb)		$963,600	Vendor Estimate/Harris Group
XII. Disposal = (1,100 lbs/hr)*(24*365)*($25.96/ton)*(1 ton/2,000 lb)		$124,064	Engineering Estimate/Harris Group
XIII. Electricity: = ($0.036/kW-hr)(8,760 hr/yr)(60 hp)(0.7457 kW/hp)/(0.70 efficiency)		$20,157	Engineering Estimate/Harris Group
Subtotal for DSI:		$1,190,904	*Calculation*
DIRECT OPERATING COSTS (DOC) - Sum of SNCR and DSI Costs:		$1,890,515	*Calculation*
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs)		$99,700	OAQPS
IX. Administration (0.02*TCC)		$300,000	OAQPS
X. Insurance (0.01*TCC)		$150,000	OAQPS
Subtotal for Indirect Costs:		$549,700	*Calculation*
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		**$2,440,215**	*Calculation*
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)		**$4,246,522**	*Calculation*
Boiler Heat Rate (MMBtu/hr)		**595**	*Design*
Normalized Stoichiometric Ratio (NSR)		**1.3**	*Fuel Tech*
NOX baseline emissions (0.30 lb/MMBtu)	tons/year	781.8	*Calculation*
NOX emissions w/ SNCR (0.20 lb/MMBtu)	tons/year	521.2	*Calculation*
Reduction from baseline	Percent	33.3	*Calculation*
Total Emissions Reduction	tons/year	260.6	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 16,295**	*Calculation*

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Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + SDA + Baghouse

TABLE E-5 - CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. SNCR	$1,500,000	AMEC database[1]
b. SDA	$3,000,000	AMEC
c. Baghouse	$3,000,000	AMEC
d. ID Fan Modifications	$1,000,000	AMEC
e. Ash System Modifications	$1,500,000	AMEC
Total Purchased Equipment Cost [TEC]	$10,000,000	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports	$980,000	AMEC
b. Site Prep	$150,000	AMEC
c. Electrical	$1,920,000	AMEC
d. Piping/Ductwork	$3,200,000	AMEC
e. Installation	$5,750,000	AMEC
Total Direct Costs [TDC](I+II)	$22,000,000	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering	$3,500,000	AMEC
b. Owner Engineering	$2,400,000	AMEC
Total Direct and Indirect Costs [TDIC](I+II+III)	$27,900,000	*Calculation*
Contingency	$3,500,000	AMEC
Operator Training	$300,000	AMEC
Startup	$300,000	AMEC
Total Capital Costs [TCC] (TDIC + Contigency + Training + Startup)	$32,000,000	*Calculation*
Total Annualized Capital Costs [TACC] (15 years @ 8.5% interest)	**$3,853,455**	*Calculation*

(1) Data from the AMEC database, based on similar projects, in-house data, and experience with new installations and retrofits.

Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + SDA + Baghouse

TABLE E-6 - DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS FOR SNCR		**Cost**	**Source**
I. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
III. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
IV. Replacement Parts (100% of maintance labor)		$27,375	OAQPS
V. Utility costs (none)			
VI. Ammonia (NOxOut®) = (34 gal/hr)*24*365*($2.07/gal)		$616,529	Fuel Tech
Subtotal for SNCR:		$699,612	*Calculation*
DIRECT OPERATING COSTS FOR SDA/BAGHOUSE			
VII. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
VIII. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
IX. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
X. Replacement Parts (100% of maintenance labor)		$27,375	OAQPS
XI. Absorbent Material		$126,671	Vendor Estimate/Harris Group
XII. Disposal		$22,881	Engineering Estimate/Harris Group
XIII. Electricity:		$104,930	Engineering Estimate/Harris Group
Subtotal for SDA:		$337,565	*Calculation*
DIRECT OPERATING COSTS (DOC) - Sum of SNCR and SDA Costs:		$1,037,177	*Calculation*
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs)		$99,700	OAQPS
IX. Administration (0.02*TCC)		$640,000	OAQPS
X. Insurance (0.01*TCC)		$320,000	OAQPS
XI. Property Taxes (0.01*TCC)		$320,000	
Subtotal for Indirect Costs:		$1,379,700	*Calculation*
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		**$2,416,877**	*Calculation*
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)		**$6,270,332**	*Calculation*
Boiler Heat Rate (MMBtu/hr)		**595**	*Design*
Normalized Stoichiometric Ratio (NSR)		**1.3**	*Fuel Tech*
NOX baseline emissions (0.30 lb/MMBtu)	tons/year	781.8	*Calculation*
NOX emissions w/ SNCR (0.20 lb/MMBtu)	tons/year	521.2	*Calculation*
Reduction from baseline	Percent	33.3	*Calculation*
Total Emissions Reduction	tons/year	260.6	*Calculation*
Cost per ton NOX Conrolled	***$/ton***	**$ 24,060**	*Calculation*

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Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + Wet Scrubber + WESP

TABLE E-7 - CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. SNCR	$1,500,000	AMEC database[1]
b. Wet Scrubber	$2,000,000	AMEC
c. WESP	$3,000,000	AMEC
d. Stack	$1,000,000	AMEC
e. ID Fan Modifications	$1,000,000	AMEC
Total Purchased Equipment Cost [TEC]	$8,500,000	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports	$970,000	AMEC
b. Site Prep	$150,000	AMEC
c. Electrical	$1,200,000	AMEC
d. Piping/Ductwork	$2,700,000	AMEC
e. Installation	$4,560,000	AMEC
Total Direct Costs [TDC](I+II)	$18,080,000	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering	$3,200,000	AMEC
b. Owner Engineering	$1,800,000	AMEC
Total Direct and Indirect Costs [TDIC](I+II+III)	$23,080,000	*Calculation*
Contingency	$3,500,000	AMEC
Operator Training	$250,000	AMEC
Startup	$250,000	AMEC
Total Capital Costs [TCC] (TDIC + Contigency + Training + Startup)	$27,080,000	*Calculation*
Total Annualized Capital Costs [TACC] (15 years @ 8.5% interest)	**$3,260,986**	*Calculation*

(1) Data from the AMEC database, based on similar projects, in-house data, and experience with new installations and retrofits.

Power Boiler No. 7
Tacoma, Washington
SNCR (0.3 lb/MMBtu Baseline NOx) + Wet Scrubber + WESP

TABLE E-8 - DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS FOR SNCR		**Cost**	**Source**
I. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
III. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
IV. Replacement Parts (100% of maintance labor)		$27,375	OAQPS
V. Utility costs (none)			
VI. Ammonia (NOxOut®) = (34 gal/hr)*24*365*($2.07/gal)		$616,529	Fuel Tech
Subtotal for SNCR:		$699,612	*Calculation*
DIRECT OPERATING COSTS FOR Wet Scrubber			
VII. Labor for operations ($45/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$24,638	Engineering Estimate
VIII. Supervisory Labor (0.15* operations labor)		$3,696	OAQPS
IX. Maintenance Labor ($50/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$27,375	Engineering Estimate
X. Replacement Parts (100% of maintenance labor)		$27,375	OAQPS
XI. Absorbent		$40,432	Harris Group
XII. Water		$505	Engineering Estimate/ Harris Group
XIII. Water treatment		$2,190	Engineering Estimate/ Harris Group
IX. Electricity		$8,718	Engineering Estimate/ Harris Group
Subtotal for Wet Scrubber:		$134,928	*Calculation*
DIRECT OPERATING COSTS (DOC) - Sum of SNCR and Wet Scrubber Costs:		$834,540	*Calculation*
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs)		$99,700	OAQPS
IX. Administration (0.02*TCC)		$541,600	OAQPS
X. Property Tax (0.01*TCC)		$270,800	
X. Insurance (0.01*TCC)		$270,800	OAQPS
Subtotal for Indirect Costs:		$1,182,900	*Calculation*
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$2,017,440	*Calculation*
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)		**$5,278,426**	*Calculation*
Boiler Heat Rate (MMBtu/hr)		**595**	*Design*
Normalized Stoichiometric Ratio (NSR)		1.3	*Fuel Tech*
NOX baseline emissions (0.30 lb/MMBtu)	tons/year	781.8	*Calculation*
NOX emissions w/ SNCR (0.20 lb/MMBtu)	tons/year	521.2	*Calculation*
Reduction from baseline	Percent	33.3	*Calculation*
Total Emissions Reduction	tons/year	260.6	*Calculation*
Cost per ton Conrolled	***$/ton***	$ 20,254	*Calculation*

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APPENDIX F

Simpson®

April 9, 2014

Mr. Stuart Clark
Program Manager
Air Quality Program
Washington State Department of Ecology
P.O. Box 47600
Olympia, WA 98504

Re: Response to EPA March 3, 2014 Letter

Dear Mr. Clark:

This letter responds to EPA's March 3, 2014 letter to you regarding EPA's review of the proposed revision of the Power Boiler 7 (PB7) NOx BACT limit in PSD permit PSD-06-02. EPA's letter explains EPA's view that the proposed revision is not warranted based on the information EPA reviewed. Simpson Tacoma Kraft (STK) respectfully disagrees with EPA's assertions for the reasons discussed below. This letter addresses each of the three criteria EPA cites for determining whether a BACT limit can be revised and shows why each one is met.

The "Ogden Memo" Criteria

EPA's letter explains that the Agency considers three criteria when determining whether a BACT limit can be revised, all of which must be met. The criteria are drawn from a November 19, 1987 EPA memorandum titled, *Request for Determination on Best Available Control Technology (BACT) Issues – Ogden Martin Tulsa Municipal Waste Incineration Facility*. The letter describes the criteria as follows:

1. Whether the source was constructed in conformity with the permit (see 40 CFR 52.21(r)(1);
2. Whether the permitted BACT levels are inappropriate as a result of errors, faulty data, or incorrect assumptions contained in the permit application; and
3. Whether the source investigated all available options to reduce emissions and demonstrated that compliance cannot be achieved.

In its letter, EPA states that it did not find any errors, faulty data, or incorrect assumptions with the original BACT determination and therefore concludes that the 2007 BACT limit and annual NOx limit were not inappropriate under the second criterion. Regarding the first criterion, EPA states that it "has likely not been met." And for the third, EPA states that STK has not provided sufficient information to make a determination. Each criterion and the reasons it is met in this case is discussed below.

Criterion 1: The source was constructed in conformity with the permit

EPA states that it "has reason to believe" that STK did not construct the cogeneration steam turbine generator project in conformity with the 2006 application and 2007 PSD Permit, referencing a February 12, 2014 letter from EPA to STK. In that letter, EPA identifies three activities that it believes were undertaken without PSD authorization: adding economizer modules, upgrading the fuel feed system, and burning more urban wood. EPA also suggests that the measured increases in NO_X emissions result, at least in part, from the latter two changes. STK believes that EPA reached these conclusions without a complete review of the facts.

STK has provided a response to EPA's February 12, 2014 letter, with copy to Ecology. The section titled "Area of Discussion #1" explains in detail why EPA's claims regarding these three activities are fully consistent with the PSD application and Permit. In summary, the application presented a scope of changes associated with upgrading steaming conditions to 875 psig and 825°F and to increasing the maximum steaming rate of PB7 to 340,000 lb/hr. The changes were purposefully broadly described in the permit application because of uncertainty before any project of this type, but the aspects salient to permit development and regulatory compliance were clearly defined.

Following that approach, the Permit broadly authorizes STK to make "[b]oiler improvements to produce the higher pressure and temperature steam required for power generation" and "[u]pgrades to #7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr." In both cases, the Permit follows these descriptions with lists of changes that the improvements and upgrades "will include," meaning the lists don't limit the authorized improvements and upgrades to only the specified changes.

STK's response to EPA shows that the economizer and fuel feed system improvements were in fact upgrades that were approved by the Permit (the list of changes the upgrades "will include" even contains the phrase, "wood fuel feed system improvements"). Regarding the claim that burning more urban wood is somehow inconsistent with the Permit, the fuel profile provided in the application projected utilization of urban wood. And because STK has historically burned urban wood and made no physical change to specifically enable additional utilization of urban wood, there is no basis to assert that burning more represents a boiler modification or departure from the assumptions relied on for permitting.

STK can find no evidence that the cogeneration project was not constructed in conformity with the Permit. The boiler modification was consistent with the physical and operational assumptions of the BACT conclusions that Ecology made during permit development (to wit, overfire air installation and combustion factor management). And there have been no relevant changes to the boiler since 2009 other than what was authorized by the Permit. The emissions calculations presented in the application, and approved by Ecology, were based on 340,000 lb/hr steaming rate and a fuel consumption rate that is conservative with respect to subsequent actual rates.

Criterion 2: The permitted BACT levels are inappropriate as a result of errors, faulty data, or incorrect assumptions contained in the permit application

EPA states that, contrary to the conclusions of Ecology's draft permit amendment, it did not find any errors, faulty data, or incorrect assumptions in the 2006 PSD Permit Application and that the 2007 NOx BACT limit and the annual NOx emission limit were not inappropriate for the cogeneration project. STK believes that there were multiple incorrect assumptions inadvertently relied on in the 2006 PSD Permit Application, and as such, relaxation of the NOx limits is appropriate.

STK submitted the 2006 PSD Permit Application before installing and operating the overfire air (OFA) system, and the permit was issued before STK had enough operating experience to determine its effect on emissions. As a result, several assumptions were made by the design engineers in order to predict future emissions from PB7 following the project. And some of these assumptions have turned out to be clearly incorrect.

Jansen Combustion and Boiler Technologies, Inc. designed and installed the new OFA system at PB7. In the two years before this installation, the average NO_x emission rate observed was 0.18 lb/MMBtu. This emission rate occurred at a time when combustion in the boiler was inefficient resulting in higher CO emissions and lower NOx emissions. During this time, firing rates of the boiler were relatively low. While the 0.18 lb/MMBtu emission rate was historically low relative to typical performance of PB7, it was already close to the initially permitted rate of 0.20 lb/MMBtu.

One goal of the OFA project was to reduce fossil fuel firing and increase hog fuel firing in PB7. Jansen expected this reduction of oil firing and increase of hog fuel firing to reduce NOx emissions. Jansen predicted, but would not guarantee, that the OFA would result in a 20% NOx emission reduction while also complying with the CO limit. Jansen's NOx performance prediction fully considered the changes to PB7 for the cogeneration project, and was therefore used as the basis for the proposed BACT limit. However, at startup after project construction STK found Jansen's assumption to be incorrect and this level of NOx control to be unachievable with the OFA technology. The NOx performance associated with the Jansen OFA system was an incorrect assumption.

The fact that the permitted BACT level was erroneous is reflected in the fact that NOx BACT emission limits for many similar boilers are higher than 0.20 lb/MMBtu and typically around 0.30 lb/MMBtu. The 0.20 lb/MMBtu limit in the 2007 PSD permit is at the low end of values typically achieved for a wood and oil co-fired boiler that relies on combustion control for NO_x suppression. Examples from the RACT/BACT/LAEAR Clearinghouse (RBLC) for permit dates between January 1991 and April 2014 are presented in the table below. In retrospect, the 0.20 lb/MMBtu level initially permitted for STK PB7 was unrealistic considering the performance of similar units.

RBLC ID	Facility/Location	Unit	Control Method	NOx Emission Limit
AL-0250	Boise White Paper Jackson, AL	Combination Boiler	Low NOx burners	0.30 lb/MMBtu (3-hr average)
WA-0337	Boise Cascade Corporation Wallula, WA	Hog Fuel Boiler	OFA system, ESP	0.30 lb/MMBtu (30-day rolling average)
LA-0188	Temple-Inland (dba International Paper Bogalusa Mill) Bogalusa, LA	No. 12 Hogged Fuel Boiler	OFA, low NOx burners, good combustion practices	0.45 lb/MMBtu (averaging period not specified)
AL-0116	Gulf States Paper Corporation Tuscaloosa, AL	Power Boiler	Low NOx burners	0.30 lb/MMBtu (averaging period not specified)
OK-0038	Weyerhaeuser Valliant, OK	Bark Boiler	OFA system	0.30 lb/MMBtu (averaging period not specified)

STK has diligently pursued optimization of PB7 combustion conditions, specifically to get NOx and CO as low as possible. These efforts have *not* resulted in NOx emissions consistently below 0.28 lbs/mmBtu. STK commissioned reviews by qualified combustion engineers. These reviews concluded that it is not technically feasible to obtain NOx emissions below 0.2 lbs/mmBtu at PB7 through combustion factor design or management (Sonnichsen Engineering Memo 2014). Failure to achieve NOx emissions below 0.2 lbs/mmBtu despite these intensive efforts further demonstrates that the BACT specification was erroneous.

Given the evidence provided in EPA's RBLC for similar units, the advice given by combustion engineers following detailed review, and STKs own experience trying to reduce NOx emissions on PB7, it is inescapable fact that the 0.20 lbs/mmBtu limit was erroneously specified due to faulty data and incorrect assumptions. Accordingly, the original BACT limit is inappropriate and revision is warranted.

Criterion 3: The source investigated all available options to reduce emissions and demonstrated that compliance cannot be achieved

EPA says that STK has not provided sufficient information, "specifically information on the quantities of salt-laden fuel currently being burned" in PB7, for EPA to determine whether this third criterion has been met. Before discussing whether STK has met this criterion, it's worth looking more closely at EPA's Ogden Memo discussion of it, rather than just EPA's single sentence summary. The Memo suggests that the requirement is actually to investigate options to *reasonably achieve* the permit limit and barring that, to lower emissions as possible.

> At a minimum the source should be required to investigate and report to the permitting agency all available options to reduce emissions to a lower (if not the permitted) level. If compliance with the permit can be reasonably achieved, the source should be required to take steps to reduce emissions. If sufficient emission reductions down to the permitted level cannot be reasonably achieved, then a reevaluation of the permit may be warranted.

It's not clear what EPA believes is necessary to meet this criterion, although we know that it considers the quantities of salt-laden fuel currently being burned in PB7 to be relevant. We read this criterion to require reasonable efforts to lower emissions to or towards the limit, without having to investigate installation of entirely new controls. We believe this is a reasonable interpretation, as it does not seem right to make a BACT limit revision hinge on investigating controls that the present BACT determined to be beyond BACT. But the fact is that STK has done both.

The mill has gone to great lengths to bring NOx emissions down. As described above, STK has been able to bring NOx emissions down to below 0.28 lbs/mmBtu (typically around 0.25 lbs/mmBtu) through optimization of PB7 combustion conditions. STK addressed fuel feed system and grate issues that caused uneven distribution of fuel on the grate. STK has experimented with air control to the point where both NOx and CO emissions have been effectively minimized. Any further reductions, even though physical changes to the air system, would not get NOx emissions much below current levels.

STK has also thoroughly investigated the feasibility of controlling NOx with add-on controls. EPA's interest in salt-laden fuel information suggests that perhaps the Agency is interested in the utilization of add-on NOx controls that involve ammonia injection (SNCR or SCR) and concerns regarding formation of ammonium chloride opacity and fine particulate (PM2.5). Detailed discussions of this concern were provided in the 2006 PSD application and in the 2010 PSD amendment application. The chloride loading to the boiler is relevant to the feasibility of NOx control through ammonia injection.

On December 20, 2012, EPA asked Ecology for a detailed accounting of sources, quantities, types, and characteristics (e.g., chloride content) of fuels and materials burned in PB7 from 2004-2005 (the period forming the basis for the PSD permit limits) and after PSD permit issuance in 2007. EPA asked for more than a general description; seeking delineation of suppliers, composition, quantities, and combination of different materials. STK provided a detailed response to EPA through Ecology, which included general descriptions, sources, specific and relative quantities, types, characteristics of all fuels burned in PB7, and laboratory analysis reports, which included the chlorine content of the fuel. The information provided showed that the biomass component of the fuel is made up of purchased hog fuels (including urban wood), recycled paper fiber residuals (OCC rejects), dewater biosolids (sludge), and wood fines. Accordingly, detailed information regarding the fuels burned and chloride content was provided to EPA. STK offered to provide additional information if necessary, but we are not aware of any further inquiry from EPA.

STK believes that the only "fuel basket" that is economically viable for the facility presents unusually high chloride loading to PB7. STK has performed very extensive fuel trials to try to achieve Boiler MACT compliance through fuel management (for the hydrogen chloride limit). The last trial in February 2014 compelled our conclusion that fuel management is not feasible and that add-on acid gas control must be employed. The prospect of controlling hydrogen chloride emissions would seem to help facilitate NOx control through ammonia injection, but that is not the case. All feasible add-on NOx control technologies result in residual ammonia "slip." No chloride control technology captures all of the chloride. Accordingly, the ammonia slip will combine with the residual chloride to form ammonium chloride fume that presents fine particulate matter emissions and may result in persistent opacity. To minimize this issue, either ammonia or chloride emissions must be exceedingly low. This circumstance adds notable complexity, cost, and operational issues, and would still present significant fine particulate emissions. STK contends that tandem control of NOx and HCl in this specific case remains not reasonably feasible.

STK has investigated other potentially available NOx control options. I noted above our efforts to reduce NOx emissions through combustion factors (design and management). Our previous applications addressed other NOx control technologies. In each case it is evident that compliance cannot be achieved without a significant "step change" in technology. To the extent the BACT selection process specifies a NOx performance level associated with a particular technology and the Ogden Memo appears to be meant to address factual errors that inadvertently make their way in to PSD permits, STK does not believe that the Ogden Memo compels a technology step change and the resultant high cost of control when the BACT performance assumption was factually incorrect. This interpretation notwithstanding, STK has investigated all available options to reduce emissions, demonstrated that compliance cannot be achieved, and therefore meets the third criterion of the Ogden Memo.

In summary, STK believes that the three criteria identified in the Ogden Memo have been met, and that a NOx BACT limit revision is consistent with PSD requirements. If you have any questions regarding the information provided or would like to discuss further, please contact me at (253) 596-0296. Thank you.

Sincerely,

Lester Keel, P.E.
Environmental Manager

CC Kate Kelly, USEPA
David Bray, USEPA (by email)
Garin Schrieve, Ecology (by email)
Jeff Johnston, Ecology (by email)

Simpson®

April 9, 2014

Edward J. Kowalski
Director, Office of Compliance and Enforcement
US EPA, Region 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

Dear Mr. Kowalski:

This letter responds to your February 12, 2014 letter to Betsy Stauffer, Registered Agent for Simpson Tacoma Kraft Company, LLC regarding PSD compliance. Simpson appreciates EPA's offer of an opportunity to meet to discuss the "Project of Concern/Areas for Discussion" identified in your letter. We have been in touch with EPA staff to arrange a meeting.

To prepare for the discussion, Simpson has prepared the enclosed written response to your letter. This enclosure provides relevant background and a project-by-project response to EPA's list of concerns. Your letter states that EPA "has reason to believe" that Simpson "may have" made changes that "appear" to have constituted a major modification, indicating that EPA is providing an opportunity to rebut the claims the letter raises. Simpson believes that the information and analysis provided in our response offers a complete rebuttal, showing that none of the projects of concern raised by EPA constituted major modifications that did not comply with PSD requirements.

Sincerely,

Dave McEntee
Vice President Operations Services
Simpson Tacoma Kraft Company LLC

cc: Stuart Clark, Washington Department of Ecology
Garin Schrieve, Washington Department of Ecology
Lester Keel, Simpson Tacoma Kraft Co. LLC

Simpson Tacoma Kraft's Response to EPA's 2/12/14 Letter

I. Introduction & Background

A. EPA's Letter Identifying "Projects of Concern/Areas for Discussion"

In a February 12, 2014 letter, EPA says that it has reason to believe that Simpson Tacoma Kraft (STK) "may have conducted one or more major modifications" without complying with PSD requirements. The letter identifies projects of concern in two discussion points titled "Simpson Projects of Concern/Areas for Discussion." In the first area for discussion, EPA says that STK undertook modifications to the #7 Power Boiler (PB7) not addressed in the application or 2007 PSD permit for the steam turbine generator project. In the second area for discussion, EPA says that emissions increases from certain facility changes between 2005 and 2009 should have been aggregated for PSD applicability purposes.

EPA concludes that one or more of the changes identified in its letter "appear to have constituted a major modification that resulted in a net emissions increase of NOx, PM, and/or SO2." EPA invites STK to discuss specifics of these changes as they relate to PSD applicability, including whether they constitute physical or operational changes, actual and potential emissions calculations, and aggregation. This response explains why none of the projects EPA identifies as of concern constitute major modifications subject to PSD review.

B. 2007 PSD Permit Authorizing the Steam Turbine Generator Project

The PSD permit issued to Simpson in May 2007 (the Permit) is central to both of EPA's areas of concern. A key characteristic of the Permit is that it broadly authorizes "improvements" and "upgrades" to PB7. Specifically, the permit findings state that the project consists of "[b]oiler improvements to produce the higher pressure and temperature steam required for power generation" and "[u]pgrades to #7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr." In both cases, these descriptions are followed by a list of changes that the improvements and upgrades "will include." Department of Ecology, *Final Approval of PSD Application for Simpson Tacoma Kraft Company*, Finding #5, May 22, 2007 (PSD-06-02).[1] By using the phrase "will include," the permit does not limit the authorized

[1] Finding 5 of the Permit states: "The proposed project consists of installation of: ...
• Boiler improvements to produce the higher pressure and temperature steam required for power generation. These improvements will include adding tube area to #7 Power Boiler's superheater section, upgrading the pressure rating of #4 Recovery Boiler's generation bank, new pressure safety valves, and piping changes to handle higher pressure steam.
• Upgrades to #7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lb/hr to 340,000 lb/hr. These will include larger forced draft and induced-draft fan motors, wood fuel feed system improvements, and possibly improvements to the ash handling, electrostatic precipitator, and other ancillary systems."

improvements and upgrades to only the specified changes. Simpson's application reflects the fact multiple improvements and upgrades, the nature and extent of which were not all fully known at the time the application was prepared and permit issued, were necessary to achieve the goal of the project.

As a result, the Permit broadly authorizes Simpson to make boiler improvements and upgrades necessary to produce higher pressure and temperature steam, and to increase PB7's steaming capacity to 340,000 lb/hr. Furthermore, the Permit's authorizations were based on an application containing emissions analyses that assumed the maximum 340,000 lb/hr steaming rate, essentially covering all of the potential improvements and upgrades that might be necessary to produce higher pressure and temperature steam, and increase PB7's steaming capacity. As shown in Section IV below, post-steam turbine generator project annual emissions have remained well within the envelope of emissions increases proposed and permitted.

II. Area for Discussion #1

A. Introduction

In the first area for discussion, EPA says that STK undertook modifications to PB7 not addressed in the September 2006 permit application or the May 2007 PSD Permit findings, namely adding economizer modules, upgrading the fuel feed system, and burning more urban wood. Each of these three projects is discussed below.

B. Projects Identified by EPA

1. Economizer module replacement

Replacing PB7 economizer modules in September 2008 was not a major modification because the change was authorized by the 2007 PSD Permit. The Permit approved improvements and upgrades to produce higher pressure and temperature steam, and to increase steaming capacity up to 340,000 lb/hr. The economizer project was part of the overall work to produce steam at the higher temperatures and pressures authorized by the permit, and did not require any additional fuel throughput. The work was implemented to increase PB7 steam efficiency and lower gas temperature to the multiclone and ESP, to allow those devices to continue to function as designed. It was work that was part of the overall effort to fulfill the Permit's grant of authority to make boiler improvements necessary to produce higher pressure and temperature steam and upgrades necessary to increase the PB7 steaming capacity.

As explained above, the Permit's description of authorized changes does not limit the scope of changes Simpson was approved to make to produce higher pressure and temperature steam, and to increase steaming capacity. But here we note that "other ancillary systems" are on the list of changes the authorized project "will include." *See* Footnote 1. Simpson considers the economizer as one of PB7's ancillary systems and believes that the economizer replacement work in 2008 was clearly authorized by the Permit.

2. Fuel feed system changes

As part of the overall effort to increase steaming capacity as authorized by the Permit, Simpson made the following changes to improve the hog fuel feed system's reliability, safety, and stability:

- Rebuild reclaimer boom for PB7 (Nov. 2008)
- Install divider walls in hog fuel bin, repair bin bottom and three floor transitions (Feb. 2009)
- Replace front wall below access doors, make angle of approach less steep (April 2009)
- Install 100 additional collars for scalper, relocate 36 inch I beam above hog fuel feed chutes, install 26 inch diameter shredder screw (Aug. 2009)
- Add three additional shredding screws inside hog fuel bin (Oct. 2009)

The latter three changes were undertaken to prevent or reduce plugging. These five fuel feed system changes were not only authorized by the Permit's general authorization to make improvements and upgrades to increase steaming capacity, but are also explicitly listed as the type of change the Permit authorizes. "[W]ood fuel feed system improvements" are specifically identified on the list of changes the authorized project "will include." *See* Footnote 1.

When preparing the 2006 Permit application Simpson was aware that fuel feed system improvements were needed to be in a position to reach a 340,000 lb/hr steaming rate, because the existing system was not capable of reaching the higher hog fuel feed rate necessary to achieve higher steaming rates. But the extent and nature of the improvements was not completely known at the time, so the application did not provide specificity of those changes. The permit, in turn, authorized general boiler improvements – in this case even specifying "wood fuel feed system improvements" – without limiting the mill to specific changes.

Simpson originally planned to replace the existing stacker/reclaimer. But lack of funding led Simpson to cancel that part of the wood fuel feed system improvements. The wood fuel feed system improvements that were undertaken were done as part of increasing the steaming rate to a maximum 340,000 lb/hr as allowed by the Permit.

3. Burning more urban wood

Changes to the percentage of urban wood fired in PB7 do not constitute a modification, major or otherwise. PB7 is a wood-fired boiler; it burns residual oil and natural gas only during start up and standby, or as a supplemental fuel. PB7 has always burned urban wood, also called construction & demolition debris, as part of the hog fuel mix. And there is no permit limit or regulation that limits the quantity or percentage of urban wood that can be burned in PB7.

STK's 2006 Permit application was based on a maximum hog fuel utilization of 254,535 tons per year. For each year following the project the actual quantity of hog fuel burned in PB7 has been below this amount. STK's records of hog fuel burned in PB7 do not differentiate urban wood from other types, but records of the quantity and type of hog fuel purchased show that (1) the mill's hog fuel utilization has been well below the rate assumed in the application, and (2) that the percentage of urban wood to total hog fuel purchased over time has fluctuated, with a recent increase. The table below provides hog fuel purchase data from 2004 to 2012.

Year	Total Purchased Hog Fuel (includes urban wood) (BDT)	Total Purchased Urban Wood (BDT)	Urban Wood Percentage of Total Purchased Hog Fuel
2004	96,610	39,469	33
2005	84,180	18,041	16
2006	101,944	22,434	16
2007	138,089	30,198	21
2008	129,740	48,599	37
2009	126,804	69,154	55
2010	177,691	74,340	46
2011	163,681	95,568	58
2012	159,609	118,914	70

Given the mill's history of purchasing and burning urban wood in PB7 – and lack of any limit on doing so – any recent increase in the percentage of urban wood fired cannot be considered a change in the method of operation. And increasing the percentage of urban wood fired does not constitute a physical change. It's worth pointing out that the hog fuel feed system is used for all types of wood fuel – there is no distinction in the system between regular hog fuel and urban wood. In other words, none of the fuel feed system changes discussed above were made for the specific purpose of accommodating more urban wood. With respect to urban wood, the facility was constructed and has been operated in accordance with the assumptions and representations made during the permitting process, and there is no basis for EPA's suggestion that increasing the percentage of urban wood burned in PB7 constituted a major modification.

C. EPA Note Regarding Simpson's Permit Amendment Request

In its first area for discussion description, EPA refers to a statement in STK's March 2010 PSD Permit Amendment Request on factors that may affect NOx and CO emissions and could be contributing to an overall increase in boiler NOx emissions. EPA says that STK listed fuel system upgrades and burning more urban wood as two of these factors. STK believes that this does not accurately describe the Permit Amendment Request.

Simpson's Permit Amendment Request listed the following as factors "that may affect NOx emissions:"

- Challenges related to the instrumentation, controls, and OFA design
- Changes in fuel to more urban wood with higher fuel-bound NOx levels
- Higher moisture content in the biomass
- Excess oxygen control
- Higher furnace temperatures leading to an increase in thermal NOx formation

- Fuel distribution on the grate. A more even fuel distribution has been shown to reduce NOx emissions
- Tube leaks in the combustion air heater that reduces the amount of combustion air that can be delivered to the furnace and reduce the available amount of over fire air

STK drew this list from a NCASI Technical Bulletin on *Factors Affecting Long-Duration NOx Emissions from Wood-Fired Boilers*,[2] to provide an idea of the types of factors that might impact NOx emissions. It is not specific to, or necessarily relevant to, PB7. It is not certain whether any of these factors have caused increased NOx emissions in STK's particular case, and as summarized in the NCASI Bulletin, the effects of the various factors can be difficult to separate and assess and those most important to an individual unit may differ from case to case. The Amendment Request was simply identifying factors with the potential to impact NOx emissions.

Referring to STK's Amendment Request statement that several other factors may affect NOx and CO emissions, EPA's letter says that Simpson listed upgrading the fuel feed system as one of the factors. This is incorrect. The Request did not mention the fuel feed system; rather, it referred to fuel distribution on the grate, which is separate from the fuel feed system changes referred to above. EPA's note on the Amendment Request also refers to urban wood fuel. But as described above, STK has always burned urban wood and has no limit on the amount of urban wood it can burn; and in any event, the amount of hog fuel burned has stayed well below the assumptions used in the 2006 Permit application analysis. The emissions calculations in the permit application were based on emission factors that apply regardless of the hog fuel mix. Even if higher urban wood burning rates were projected as part of the project, there would be no change in the emissions calculations.

III. Area for Discussion #2

A. Introduction

In the second Area for Discussion, EPA says that a series of changes to PB7 between 2005 and 2009 were either permitted separately or not permitted, "despite internal documents showing that these changes were viewed as part of one plan." EPA says these changes included the steam line project, over fire air project, steam turbine project, and the changes listed in Simpson's March 24, 2010 PSD Permit Amendment Request, as well as changes to the Recovery Boiler and Digesters during the same period. EPA says that Simpson did not evaluate the aggregated effects of these projects consistent with EPA PSD guidance on project aggregation.

B. EPA Approach to Aggregation

Simpson's understanding of EPA's aggregation policy is that projects occurring in a similar time frame and which depend upon one another for their economic or technical viability should normally be permitted as a single project, in which case their emissions would be "aggregated" in the first step of the PSD applicability review. EPA issued a rule in January 2009 that would have created

[2] National Council for Air and Steam Improvement (NCASI), *An Analysis of Factors Affecting Long-Duration NOx Emissions from Wood-Fired Boilers: Technical Bulletin No. 914*, Section 2.0.

a regulatory approach to aggregation, but the rule never became effective. Previous case-by-case determinations, therefore, continue to be EPA's primary guide to approaching aggregation.

Still, EPA's rulemaking discussion remains relevant to the extent it characterizes the Agency's historical case-by-case approach. In a notice proposing to revoke the rule, EPA stated that, "[h]istorically, EPA has analyzed the question of whether nominally-separate changes are one change by using a case-by-case review of all relevant and objective factors that looks for 'indicia,' or indicators, of these changes being one common aggregate change." 75 Fed. Reg. 19567, 19571 (April 15, 2010). In the same notice EPA described its 3M-Maplewood determination as the Agency's "most complete statement of the principles regarding grouping nominally-separate changes," which requires aggregating "any group of small changes that are sufficiently related" to fit within the ordinary meaning of a single physical or operational change. 75 Fed. Reg. at 19571.

EPA's 3M letter describes five criteria: (1) minor source permit applications within a short period (generally 12-18 months) that would be subject to major NSR if aggregated; (2) funding applications, to determine if a project wouldn't be funded or be economically viable without another (which would be "evidence of circumvention"); (3) reports of consumer demand and projected production levels; (4) statements regarding operational plans, and (5) EPA's own analysis of economic realities of the projects considered together. Letter from John Rasnic, U.S. EPA, to George Czerniak, EPA Air Enforcement Branch, *Applicability of New Source Review Circumvention Guidance to 3M - Maplewood, Minnesota*, Aug. 3, 1996.

Before presenting the five criteria, the 3M letter discusses EPA's authority on aggregation as being based in the need to avoid new source review "circumvention." The criteria were intended to serve as "objective indicia to identify circumvention situations." *3M - Maplewood* at 2. This focus on circumvention, which Webster's defines as "gain[ing] advantage over by stratagem or deception," continues in EPA's later aggregation policy descriptions. In its notice proposing to revoke the aggregation rule, EPA described its aggregation policy as developing over time "in response to a need to deter sources from attempting to expedite construction by permitting several changes separately as minor modifications." 75 Fed. Reg. at 19568. And in a 2011 letter discussing aggregation, EPA stated that it "may enforce the major source permitting requirements in cases when a source 'circumvents' major NSR by dividing one change and its emissions increase into nominally-separate physical or operational changes." Letter from S. Page, Director, OAQPS, to D. Isaacs, Semiconductor Industry Association, Aug. 26, 2011, p. 7.

For purposes of Area for Discussion #2, determining whether Simpson circumvented PSD review for the identified changes entails two questions. First, are any of the projects "sufficiently related" to warrant aggregation? Second, if yes, would aggregating emissions from those projects have constituted a major modification? The first question entails reviewing the extent of the economic and technical relationships between the projects. Questions to ask include: Are the projects economically or technically dependent on each other? Would one not be economically or technically viable without the other? In EPA's words, are they "nominally separate" – separate in name only? Relevant information includes projected production levels, statements on operational plans, and documentation on project scope, purpose, and funding.

Regarding technical dependence or independence, EPA has noted that "simply because a physical or operational change occurs at the same process unit as a previous change does not automatically establish a substantial relationship," noting a comment that "'[a]lmost all plant improvements are dependent on another piece of equipment as a technical matter.'" 74 Fed. Reg. 2378 (Jan. 15, 2009). In other words, there is a threshold. There has to be more than a relationship; the relationship must be sufficient ("substantial" in EPA's intended regulatory framework) to warrant aggregation.

C. Projects Identified by EPA

To respond to EPA's comments on aggregation, Simpson identified the following specific projects as fitting EPA's general descriptions of changes to Power Boiler 7 between 2005 and 2009 and projects involving Recovery Boiler 4 and the Kamyr Digesters. For the latter, the projects identified are based on the response to Question 19 of the original Section 114 request, dated April 29, 2011.

Projects	Authorization Date
Recovery Boiler 4 Projects	
Repair 40 floor tubes	February 14, 2005
Repair 30 floor tubes	March 8, 2007
Kamyr Digesters Projects	
Replace top circulation pump on Kamyr Digester 1	August 1, 2005
Replace and lower Kamyr Digester 2 extraction screens	October 4, 2006
CBOP Steam Line Projects	
Installation of steam line from STK to CBOP	2005
PB7 OFA Projects	
Installation of modern over fire air system	December 19, 2005
Steam Turbine (RB4 and PB7) Projects	
Boiler modifications for cogeneration project	May 30, 2007
PB7 Projects from Amendment Application	
Human-Machine Interface Replacement	December 10, 2007
Install redundant operator interface network	December 10, 2007
Reclaimer rebuild	November 6, 2008
Replace generator bank	November 20, 2008
Work on the burner management system	December 30, 2008
Hog fuel bin repairs	February 7, 2009
Work on the hog fuel bin to prevent plugging	April 18, 2009
Hog fuel feed work to prevent plugging	August 24, 2009
Optimization for O2, CO, and NOx control	August 24, 2009

Each of these projects is discussed below. For each, the response explains why aggregation is not warranted, either because the identified change was sufficiently separate or because the work was authorized by the steam turbine generator PSD Permit. Contrary to EPA's suggestion, there is no evidence that Simpson circumvented PSD requirements by pursuing any of the listed changes as independent projects.

Finally, this response addresses EPA's aggregation claims at face value, responding in the context EPA has provided by using the Agency's criteria to evaluate whether aggregation was warranted. In so doing Simpson is not changing or relinquishing its view that some of the changes discussed were not modifications subject to new source review, for instance because they qualified as routine maintenance or repair or any other applicable exception or exemption.

1. Recovery Boiler 4 (RB4) Projects

The two RB4 projects undertaken between 2005 and 2009 were to repair floor tubes within the boiler. On two separate occasions during routine, scheduled maintenance in 2005 and 2007, it was discovered that a section of the RB4 floor was badly bowed. In January 2005, follow-up survey work indicated that a portion of the tubes in the southwest portion of the furnace floor were bent up from 2 to 3.5 inches. To repair the deformed tubes, four ten-tube panels were placed. In January 2007, the follow-up survey work found a section of deformed tubes in the southeast portion of the furnace floor, requiring replacement of three ten-tube panels.

The purpose of the RB4 work in both cases was the routine repair of damaged floor tubes. The words "damage" and "repair" are used multiple times in both requests to fund the work. *See* Authorization for Capital Expenditure (ACE) numbers 05042 and 07058.[3] It was work that would have been performed regardless of whether STK chose to pursue any of the other identified projects, including the steam turbine cogeneration project.

In both cases, the tube repair was necessary to allow RB4 to continue operating in a normal manner. There was no technical or economic relationship between these two instances of repairing bent tubes and projects at any other unit in the mill sufficient to warrant aggregation. PB7 has the ability to operate, and historically has operated, during periods of downtime in the recovery operations of the mill. Conversely, during periods when PB7 is shut down, steam can be supplied to other areas of the mill from other combustion sources, such as RB4 or Power Boiler 6 (PB6). RB4 and PB7 can and do operate independently of each other, and the RB4 tube repairs were not technically related to other projects, including the cogeneration project. These tube repairs also did not share a sufficient economic relationship with other projects. The repairs were economically justified and viable on their own; the repairs were necessary to allow RB4 to fulfill its purpose at the mill and would have been undertaken regardless of whether any other project was pursued.

2. Kamyr Digester Projects

Between 2005 and 2009, STK undertook two Kamyr Digester projects. A 2005 project authorized work on Kamyr Digester 1 to replace the top circulation pump motor, with associated wiring and starter, impeller and wear rings. The work was expected to eliminate top circulation line pounding by allowing a slowing of the high pressure feeder. This purpose of this relatively small project was, therefore, to address a technical issue unique to the unit itself. A 2006 project authorized work on Kamyr Digester 2 to replace worn liquor extraction screens. Under this project, the screens in Kamyr Digester 2 were replaced with similar screens (like-for-like replacement), and the horizontal Savcor rings were replaced with vertical rings. The new screens were placed 12-15 feet lower inside the digester. By placing the screens at a lower level, STK expected to lengthen the cooking zone, reduce hang-ups, improve pulp quality and reduce energy consumption. In a letter dated February 20, 2007, Ecology notified STK that this project did not trigger PSD review.

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[3] Simpson provided copies of the ACEs to EPA in its original response to EPA's Clean Air Act Section 114 Information Request.

These two projects were not sufficiently related to other changes occurring within 12 to 18 month of each to require aggregation. The projects were designed and intended (as reflected in the Authorization for Capital Expenditure for each) to address issues specific to each digester unit – to reduce line pounding in Kamyr 1 and to improve pulp quality and reduce energy consumption in Kamyr 2. Digesters use steam to cook wood chips to produce pulp. But the mere fact that the digesters use steam produced by other units at the mill does not create a "sufficient relationship" (note that they can use steam from any of the steam-producing units at the mill). These projects did not depend in any way, economically or technically, on any other contemporaneous projects. They were viable and justified on their own merits, and would have been carried out regardless of other changes at the mill.

3. CBOP Steam Line

Simpson built a steam line from STK to Simpson Timber Company's Commencement Bay Operations (CBOP) sawmill in an effort to allow CBOP to replace most of the natural gas being used for heating at CBOP. The project began operating in February 2006. But the steam line proved difficult to control and operation of the line subsequently ceased.

At the time of the proposal, the CBOP mill was using hot oil heaters fired by natural gas to heat its lumber kilns. The three boilers at STK (RB4, PB6, and PB7) were not operating at full rate and therefore had the ability to supply steam to CBOP. The project added a 3,200-linear foot, 10-inch steam supply line from STK to CBOP, and a return steam condensate line from CBOP to STK to aid in further steam production. CBOP installed a steam/oil heat exchanger. STK installed valving and monitoring systems to maintain the required system flows and pressures to prevent steam drops that could lead to a process upset at STK.

The CBOP steam line project was an independent project, economically and technically justified on its own merits. Installing the steam line to CBOP was intended to provide economic advantages to both facilities – advantages that were not dependent on any other project. For STK, it provided the opportunity to collect revenue for excess steam. For CBOP it provided the opportunity to reduce dependence on fossil fuel.

Nor was the steam line project technically dependent on any other project that occurred within 12 to 18 months of it. For instance, the steam exported to CBOP would not have been used in the cogeneration process at all; only steam retained at STK is used for cogeneration. The fact that use of the steam line has been discontinued shows the complete lack of technical interdependence with other projects. All other contemporaneous projects have continued to operate after the decision to cease using the steam line.

4. PB7 Over Fire Air (OFA) Project

STK installed a modern over fire air (OFA) system on PB7 in 2006 after obtaining Ecology review and approval. The OFA project was borne out of a 2005 engineering study conducted by Jansen Associates, which found that the then-existing OFA system was not effective for current operations because it was designed for a small portion of the air required for combustion, with most of the air going under the fuel and through the grate. This was not optimum for wood fuels due to their large volatile component and consequently the existing OFA system was not able to sufficiently burn out char carryover. To replace the old system, the new OFA project included removing the existing OFA and ports, installing four new ports on each side wall, new duct work, OFA nozzles and furnace penetrations, air heater modifications, air measurement devices, modifications to the fuel distribution bin to provide even fuel distribution, a new multiclone dust collector, modifications to the ash handling system, and new instrumentation and controls.

The purpose of the new OFA system was to allow PB7 to burn solid fuel more efficiently (i.e, produce the same quantity of steam using less overall fuel). Specific goals of the project included an increase in wood firing with a simultaneous reduction of oil firing, reduced CO emissions, and a reduced need to run PB6.

The OFA project was viable and justified a stand-alone, independent project both technically and economically. From a technical perspective, independent boiler experts had determined that the old OFA system was no longer effective for then-current operations. As discussed in the ACE for the project, this lack of effectiveness coupled with wood fuel quality degradation caused difficulty in controlling boiler CO emissions, which in turn resulted in having to burn more fuel oil than desired. To counteract the negative effects of the ineffective OFA system, the mill had to turn to oil firing to help complete combustion in the firebox and control unburned carbon carryover into the back passes. These problems were unique to PB7 and unrelated to any other changes before or after installation of the new OFA system. The new OFA system was necessary to stabilize combustion, increase thermal efficiency, allow better control of NOx and CO emissions, and minimize the need for excess hydrocarbon fuel usage.

Economically, the new OFA project was clearly independent and viable on its own merits. By decreasing the amount of fuel oil burned, the ACE projected the new system to save over $1.4 million per year. And the project was expected to save additional costs by reducing the excess hog fuel usage associated with the inefficiency caused by the old system, reducing the volume of ash requiring disposal, and reducing or eliminating having to respond to fires in the mulitclone hoppers. Given the significance of these savings, the economic viability of the OFA project clearly did not depend on other changes at the mill.

As an independent project with its own clear economic and technical justifications, making it a project Simpson would have pursued regardless of any other previous or subsequent changes, the new OFA system was not sufficiently related to any project at the mill to warrant aggregation. Simpson understands that the ACE for this project (ACE 05109, dated 11/4/2005), is the internal document referenced in EPA's February 12, 2014 letter that EPA describes as "showing that these changes were viewed as part of one plan," and therefore presumably ripe for aggregation. Simpson believes this is a faulty characterization. First, the summary on the first page of the ACE describes the project and its justifications without any reference to the steam turbine generator project. Second, the language to which EPA refers comes after a numbered list describing the project purpose on the standalone grounds described above. The "Purpose" of the project is described in these four numbered points. The language that EPA describes as "showing" that various changes were "viewed as part of one plan" comes after this numbered list, and after the explicit preface "[w]hile this project is justified on its own merits...."

As Simpson noted in response to Question 19 of EPA's original Section 114 request, ACE text is in some respects a pitch for funding. That is the case for the language that EPA is focused on. Simply because the ACE author attempted to make his case for OFA funding more attractive by adding the statement that it would facilitate development of cogeneration – something that at the time was still speculative and not a sure thing – does not make the projects technically or economically dependent, and most certainly does not mean, as EPA suggests, that Simpson viewed the projects as part of one plan.

That said, taking the statement that the steaming benefits anticipated from OFA were a condition-precedent to cogeneration at face value, Simpson understands why EPA has highlighted these projects in the context of aggregation. It seems fair to say, while Simpson believes that the facts clearly support the conclusion that OFA was appropriately permitted as a separate, standalone project, that if it had not been implemented earlier, it (or something like it) would have been included as part of the cogeneration project. So, to the extent EPA believes that OFA should have been included in the applicability analysis for the later cogeneration steam turbine generator project, the second aggregation question is relevant: would aggregating emissions from the two projects have constituted a major modification?

Because the cogeneration project was itself a major modification that went through PSD review, the relevant question is whether including OFA in the analysis would have changed anything about the 2006 cogeneration project application. The answer is no. Even if the project application had included OFA, the emissions analysis would not have changed. The baseline emissions considered in the application were based on the 1996-2005 time period – the same period that would be applicable to OFA, which was installed and began operating in 2006. Emissions related to the OFA project were below the significant emission rates for triggering PSD permitting. And even if the OFA project emissions had been aggregated with the cogeneration project, the emissions analysis presented in the application would not have changed, as those projected emissions already included projected emissions related to the OFA project.

5. Steam Turbine Project

As noted above, the PSD Permit for the cogeneration steam turbine generator project authorized multiple changes at the mill to allow PB7 and RB4 to produce the higher pressure and temperature steam required for power generation and to increase PB7's maximum continuous rated steaming capacity to 340,000 pounds per hour. Therefore, to the extent any of the other projects identified by EPA fall within these authorizations, they were approved and an aggregation analysis would be moot. To the extent EPA is alleging that other projects should have been aggregated with the cogeneration project, Simpson's response is provided in sections specific to the other projects. These responses show that under EPA's criteria, each of the other projects was sufficiently separate from the cogeneration project, and each other.

Simpson went through the PSD permitting process for all the changes necessary to implement the cogeneration project. And the other changes either did not constitute modifications at all, or were technically and economically justified on their own merits and not dependent on other projects. Further, Section IV below presents an overall NSR screening analysis to demonstrate that even if aggregation was applied, the projects would not have triggered PSD permitting review.

6. Changes Listed in 2010 Permit Amendment Application

Simpson's March 24, 2010 PSD permit amendment application provides a chronology of events and changes at the mill relevant to the NOx emissions issue that was the subject of the request. As discussed below, Simpson believes that these changes were either authorized by the PSD permit, weren't sufficiently related to other projects to warrant aggregation, or did not result in an emissions increase.

a. Human-Machine Interface Replacement and Redundant Operator Interface Network

STK replaced PB7's obsolete Human Machine Interface (HMI) Screens in 2008. The HMI screen ACE description is simple and direct: "Replace the obsolete operator interface (HMI) screens in #7 Power Boiler control room. Parts are no longer available for these screens." ACE 08013, Nov. 15, 2007. The purpose was similarly fundamental: to allow continued operation of the boiler. The ACE describes the consequences of not approving the change as "[u]nable to run #7 Power Boiler." As part of the HMI screen replacement, STK also authorized a redundant communication and control path between the existing Bailey I/O and the newly-purchased HMI screens. ACE 08014, Nov. 15, 2007. The redundancy eliminated a single point of failure for the PB7 operator interface network, allowing the boiler to continue operating while troubleshooting of the primary communication and control path was in progress. The work occurred in several portions during 2008.

There was no technical or economic relationship between these two changes at PB7 and any changes at the mill sufficient to warrant aggregation. The work was technically justified on an independent basis – without the new screens the boiler would cease to function, and without the redundant interface network, the boiler would have remained vulnerable to system failure, resulting in upsets and shutdowns (things that EPA typically encourages sources to invest the money to avoid). These changes also did not share a sufficient economic relationship with other changes. The changes were economically justified and viable on their own. Without the first, the boiler would become inoperable, with an obviously devastating economic impact. For the second, avoiding a single boiler shutdown provided sufficient independent economic justification: the ACE states that "[o]ne boiler downtime due to single point failure will pay for this upgrade."

Both of these changes were to address specific deficiencies and would have been pursued regardless of any other changes at the mill. Even if these changes had been aggregated with others, it wouldn't have made any difference, as there were no emissions increases associated with them. Finally, although the company approached the changes as necessary to maintain the boiler's existing operational capabilities, these changes to replace the HMI screens and install a redundant communication system could also reasonably be viewed as changes necessary to produce steam for cogeneration, as authorized by the PSD Permit.

b. Hog Fuel Delivery System Improvements

These improvements included the rebuilding of the reclaimer boom, repairs of the hog fuel bin, and repairs to mitigate fuel plugging. These improvements are addressed in Section II.B.2 above, which explains that these changes were authorized by the steam turbine generator PSD Permit.

c. Generator Bank Replacement

At the end of 2008 STK did work to address the fact that over 500 generating bank tubes in PB7 had wall thicknesses below the allowable ASME minimum for operation at a steaming pressure of 500 psig. A corrosion mechanism called Near Drum Thinning was affecting some tubes, but the design tube thickness needed to be improved in order to meet the higher cogeneration steam demand. STK replaced these tubes with steel tubes of 0.180 inch wall thickness (the maximum practical wall), a 2-inch outside diameter rather than 2.5 inch to reduce flue gas velocity, and installed them with stainless steel shields next to the steam and mud drums. This work did not increase the boiler's maximum capacity; it merely allowed Simpson to continue operating the boiler in a safe and effective manner. The 2005 Jansen study noted that the average flue gas velocities would slightly exceed industry guidelines at higher steaming capacities, and that this would increase erosion and maintenance costs in the future. The 2-inch diameter was specifically recommended by the Jansen study to reduce inlet flue gas velocities and in turn future erosion and maintenance costs. This multi-pronged approach was chosen to mitigate the causes of Near Drum Thinning.

As discussed in Section I.B above, the steam generator turbine PSD Permit gave broad authorization to make boiler improvements and upgrades necessary to produce higher pressure and temperature steam, and to increase PB7's steaming capacity to 340,000 lb/hr. Among those improvements were changes like this, where the potential for having to make the change existed, without any certainty at the time of permitting that it would be necessary. The need to make these changes to address Near Drum Thinning was a change that turned out to be necessary to fulfill the PSD Permit authorization. Because the generator bank work was allowed under the Permit, there is no basis for aggregation (it was, in effect, already aggregated). The project did not increase the maximum capacity of the boiler, and the work was permitted as part of the cogeneration project.

d. Burner Management System

The burner management system (BMS) upgrade was a safety project. It included purchasing additional instrumentation in order to meet code-specified boiler air purge requirements and boiler minimum combustion air flow requirements. Changes to the gas header piping in order to comply with the code were also required. The project brought the boiler into compliance with the NFPA 85 Boiler and Combustion System Hazards Code, and insured safe operation of the boiler.

There was no technical or economic relationship between this and any other changes at the mill sufficient to warrant aggregation. The work was technically justified in an independent basis – it simply added instrumentation and piping to come into compliance with boiler safety code provisions. The change was also economically justified and viable on its own merits, and did not share a sufficient economic relationship with other changes. The ACE described the benefits as "insur[ing] the safe operation of #7 Power Boiler" and "[b]ring[ing] the boiler into compliance with NFPA 85 Boiler and Combustion System Hazards Code." ACE 09036. In other words, the work was independently justified from an economic perspective because it would avoid the potential costs associated with operating a potentially unsafe boiler. The work did nothing to change the boiler specifications and therefore no emissions increases were associated with it.

e. Power Boiler Optimization – O2, CO, and NOx Control

Following an evaluation of air, water, hog fuel, gas, and oil control loops for PB7, control schemes were implemented to allow for automatic operation of control loops focusing on excess combustion air, carbon monoxide, and nitrogen oxide emissions. The goal of the project was to minimize excess oxygen, carbon monoxide, and nitrogen oxides, and optimize operation of the boiler. This work was simply for additional control loops, with no impact on the boiler specifications. It was work undertaken pursuant to the steam turbine generator PSD Permit; work considered necessary to put the boiler in the best position to meet the Permit's emissions limits for CO and NOx. Reducing excess oxygen was also expected to result in a 2 percent increase in boiler efficiency. Even if this work was determined to be outside of the Permit scope and aggregation warranted, there were no emissions increases associated with it.

IV. Emissions Screening Analysis

This response to EPA's 2/12/14 letter explains why the projects identified by EPA were either authorized by the steam turbine generator PSD Permit, were not modifications subject to new source review, or were not subject to aggregation because they did not have a sufficient technical or economic relationship to other projects. But to further show that there is no basis for EPA's claim that one or more of the identified changes appear to have constituted a major modification, Simpson has conducted a NSR screening analysis to evaluate the aggregated effects of the projects on emissions of all criteria pollutants.

The result of the emissions screening analysis is provided in table below. This analysis is for screening purposes only and does not represent a formal PSD netting analysis. Any year-to-year emissions increases in the calculations may be due to any number of factors, so they cannot be attributed to any particular project without further analysis. Furthermore, the analysis takes a conservative approach; it does not subtract emissions that could have been accommodated during the baseline period and that are unrelated to the change in emissions (also referred to as the demand growth exclusion).

Overall NSR Applicability Screening Analysis – PB7, RB4, & Digesters

Pollutants	Actual Emissions (tpy)[(1)(2)]	Baseline Emissions (tpy)[(1)(3)]	Emission Increase (tpy)[(a)]	Significant Emission Rates (tpy)	Emission Increase > Significant Emission Rates	NSR Applicability
PM	187	217	0	25	**NO**	**NO**
PM_{10}	171	192	0	15	**NO**	**NO**
$PM_{2.5}$	139	171	0	10	**NO**	**NO**
SO_2	356	816	0	40	**NO**	**NO**
NO_X	840	637	203	40	**YES**	**YES**
CO	1327	2032	0	100	**NO**	**NO**
VOC	98	66	31	40	**NO**	**NO**
TRS	15	14	2	10	**NO**	**NO**
Lead	0.02	0.02	0.00	0.6	**NO**	**NO**

Calculations:
(a) Emission Increase (tpy) = Actual Emissions (tpy) - Baseline Emissions (tpy).
Where the emissions increase is negative it is shown as zero.

Notes:
(1) Actual and baseline emissions reflect emissions from Recovery Boiler No. 4, Power Boiler No. 7, Smelt Dissolving Tanks 4E & 4W, Lime Kiln No. 1, and Lime Kiln No. 2.
(2) Actual emissions are the maximum annual emissions from 2010-2012.
(3) Baseline emissions are the average of 2 consecutive years from 1995-2004.

The results show that NOx is the only pollutant with emission increases above the PSD significant emission rate. But these emission increases can mostly be attributed the cogeneration steam turbine generator project, which went through PSD review. The PSD Permit (PSD 06-02) allowed NOx emission increases of 233 tons per year over the baseline emissions for PB7 only. Even with the inclusion of RB4 and Digesters in the emissions screening analysis, NOx emissions increases are still below the emissions allowable under the PSD Permit.

V. Conclusion

EPA's 2/12/14 letter claims that STK (1) made changes at PB7 not addressed in the steam turbine generator PSD application or Permit and (2) did not aggregate certain facility changes made between 2005 and 2009. EPA has invited Simpson to discuss the Agency's view that one or more of these changes "appear" to have constituted a major modification, indicating that EPA is providing Simpson the opportunity to rebut the claims raised in EPA's letter. Simpson believes that the information and analysis provided in this response show that none of the projects of concern raised by EPA constituted major modifications.

Two PB7 projects that EPA claims weren't addressed in the PSD application or Permit – the economizer and fuel feed system upgrades – were actually well within the Permit's broad authorizations for improving and upgrading PB7 to produce higher pressure and temperature steam, and to increase steaming capacity. The third, burning more urban wood, is a fuel percentage change that the mill is free to make without regulatory consequence, as it is a fuel the unit has always used with no restriction on amounts.

The projects for which EPA says Simpson did not evaluate aggregated effects were either sufficiently independent from other projects so as to not warrant aggregation under EPA's criteria, or were authorized under the steam turbine generator PSD Permit. EPA's letter lists projects that had clear independent justification. The RB4 tube repairs, digester changes to eliminate unit-specific issues, CBOP steam line with its own unique economic rationale, ineffective overfire air system replacement, boiler control upgrades, and burner management system upgrades to assure code compliance were all technically-independent changes that were economically viable on their own. None of these projects were separate in name only (nominally-separate); they were in fact separate.

The remaining projects on EPA's aggregation list – the hog fuel feed system upgrades and PB7 generator bank replacement – fell under the Permit's broad authorizations for improving and upgrading PB7. For these projects, it's hard to understand how EPA can imply that Simpson somehow deceived or circumvented PSD in order to expedite construction when the company actually went through the PSD process, applying for and receiving a permit authorizing the type of changes that EPA now suggests may warrant enforcement.

From: Dossett, Donald [mailto:Dossett.Donald@epa.gov]
Sent: Tuesday, April 29, 2014 4:29 PM
To: Johnston, Jeff (ECY)
Cc: Keel, Lester
Subject: Simpson Tacoma Kraft (STK) - PSD permit amendment

Jeff,

Over the past several weeks, EPA staff have had two technical meetings with STK and have exchanged numerous emails with technical information related to the three "Ogden" criteria laid out in Kate Kelly's March 3, 2014 letter to Stu Clark. Specifically, STK provided the following information that was not in the permit record for the May 22, 2007 PSD permit or STK's August 2010 request to Ecology to revise the NOx BACT limit for Power Boiler No. 7 (PB7) in the PSD permit and had not been provided to EPA prior to Kate's March 3, 2014 letter:

- A July 28, 2006 letter from Jansen to STK titled "NOx BACT Review – No. 7 Power Boiler Jansen Project No, 2006-0021," which acknowledges the uncertainty of the 2006 permit application estimate of the post-modification NOx emission rate.

- Substantial information on the types, quantities, and moisture content of fuels, especially purchased biomass, combusted before and after the modification to PB7, documenting the moisture content of as-combusted biomass over time.

- Information on PB7 boiler operating loads and as-combusted fuel moisture correlated with NOx emission rates before and after the modification.

- Substantial information on the chloride content of fuels and the HCl concentrations in the exhaust gas from PB7, documenting the high chloride levels which would be available to react with ammonia.

- Information on the construction and operation of PB7 subsequent to the 2007 PSD permit (provided in STK's April 9, 2014 response to EPA's February 12, 2014 letter regarding potential PSD compliance concerns).

Provided STK supplements its 2010 permit revision application with the information listed above, the criteria in the Ogden memo for revising the NOx BACT limit would appear to be satisfied. We have also asked STK to update the NOx BACT analysis for PB7 to evaluate the cost-effectiveness of a technically feasible control scenario – a combination of controls to reduce HCl and NOx (acid gas scrubbing and SCR/SNCR along with any needed improvements in PM control).

We plan on sending a more formal response (Kate to Stu) to update Kate's March 3, 2014 letter once we receive a copy of the supplement to the application.

If you have any questions, don't hesitate to give me a call or have your staff contact David Bray at (206) 553-4253.

Don

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